GENERATION PLANNING PROCESSES

Memorandum of

ONTARIO HYDRO

to the

Royal Commission

on Electric Power Planning

with respect to the

Public Information Hearings

May, 1976

I N D E X

11.0 GENERATION PLANNING PROCESSES

11.1 INTRODUCTION

The selection of a satisfactory program for generation development involves the following steps:

(a) Determine the requirements for new generating sources.

(b) Determine the constraints in the manner in which the requirements can be met.

(c) Determine the feasible alternatives, i.e., those which meet the requirements and conform with the constraints.

(d) Compare the feasible alternatives by weighing up and trading off their advantages and disadvantages.

(e) Identify the best alternative, when all factors are considered.

This memorandum discusses the factors involved in the above five steps and outlines Ontario Hydro's current proposals for future development of generation resources.

The dominant factors affecting the five steps in the selection process are safety, reliability of power supply to customers, environmental effects, and cost. The culmination of the selection process for new generation and its associated transmission answers the questions: what type and characteristics of generation, how much, when and where.

Having arrived at the answer to the questions of what, how much, when, and where a new facility must come into service in order to meet future requirements, one can estimate the time at which the facility must be finally committed for design and construction, and the earlier times at which the processes for public participation and obtaining project approvals should be initiated.

Forecasts of future conditions and requirements for generation are always subject to uncertainty. The further into the future that one extends a forecast, the greater is the amount of the uncertainty; that is,

the greater will be the likelihood of substantial differences between the forecast conditions and those which actually occur. Therefore, it is not reasonable to devise a single, specific, fixed, year-by-year program of new facilities for the next 20 years. As actual future events unfold, it would be necessary to modify such a program. The actual process of releasing new projects for design and construction is to make these releases in a series of discrete steps. Release of each new project is made only when its release becomes essential.

However, it is necessary to attempt to ensure that each project, when it is released, will be useful throughout its life. It is also necessary to maintain as much flexibility as possible for meeting actual future conditions which differ from those estimated at the time of release. Therefore, in determining the nature of a facility, it is necessary to examine long range projections of future electric system development for periods of 20 or more years ahead, in order to determine whether the proposed facility will:

- be needed;
- meet technical and financial constraints;
- meet expected environmental and social constraints;

- serve a useful function throughout its life;
- provide sufficient flexibility to allow Ontario Hydro to meet the uncertainties of the future; and
- permit future development of substantially superior projects, if and when they become available.

In determining the time when a facility is needed to come into service, and hence in determining when it must be released for design and construction, the primary emphasis is upon:

- the load forecast from the present to the time the facility should come into service, and not on the load forecast beyond that time. In practice, this means the load forecast extending up to 14 years into the future.
- the alternative facilities which can be developed in this time span of 14 years. These alternatives are largely confined to those which

are currently feasible from the technical, environmental, and cost viewpoints.

The Ontario Hydro system comprises two parts, the East System and the West System (which are separated by a line roughly running north through Wawa). Because of the relatively small transmission capacity interconnecting them, the planning of the two systems is in large measure done separately. It is possible that in future this transmission capacity will be substantially increased, and this will enable integrated planning for the whole province. Although the technical characteristics of these two systems are somewhat different, the principles of planning generation and transmission are similar for both.

11.2 REQUIREMENTS

The requirements for new generation and associated transmission are determined solely by the electric load that is forecast to arise in future years, and by the required reliability of supply to that load. If in future Ontario Hydro cannot build sufficient new facilities to meet the forecast requirements of the load, it may become necessary to reduce the reliability of supply and/or place government restrictions on the future growth of electric load.

A. Electric Load

To the electric utility the power and energy which it supplies to customers is known as the electric load. The term is used to describe the power and energy supplied to various parts of the system, e.g.:

(1) At the individual customer's premises.

(2) At main transformer stations which supply many customers. The load at a transformer station reflects the sum of the loads of individual customers supplied from it, the diversity amongst these loads, and the power and energy losses in supplying power and energy from the transformer station to the individual customers.

(3) At generating station output buses. The load at these buses reflects the sum of the loads of all customers supplied by the electric system, the

diversity among them, and the power and the losses throughout the whole system in supplying power and energy to the customers.

Diversity is the term used to reflect the fact that the peak loads of various customers may occur at different times of the day or year. As a result, the combined peak load of these customers is less than the arithmetic sum of the individual customer peak loads.

Ontario Hydro supplies the following four categories of load:

(1) Primary - Firm

Firm load is suppled on a commercially continuous basis, 24 hours per day, every day, in the load pattern which the customer requires.

(2) Primary - Interruptible

Interruptible load is supplied on a continuous basis, year-round, except in certain periods which are described in the Power Supply Contract. In practice, interruptible loads are supplied by using system reserve capacity, and the supplies are interrupted when reserve capacity is needed to supply firm loads.

(3) Standby

This is power and energy which Ontario Hydro will supply on an intermittent basis to certain customers who own and operate their own generating facilities. It is supplied only during those occasions when a customer has some of his generation unavailable because of forced or scheduled outages.

(4) Secondary

This is power and energy sold on a non-continuous basis. Customers use it to replace more costly energy production from their own generating facilities or to reduce their consumption of fossil fuels. Cessation of secondary sales may affect the customer's operating costs, but should not affect his normal processes, because he has alternative facilities which he can use to maintain his processes. Ontario Hydro sells

secondary power and energy if and when it has available productive capacity in excess of the requirements of its primary and standby loads, and if it can derive net profit from the sales. The net profit is used to reduce the effective cost of power to Ontario Hydro's primary load customers.

The National Energy Board uses the term "surplus interruptible" power and energy to describe what Ontario Hydro internally defines as "secondary" power and energy.

In Ontario Hydro's case, the future requirement for new generation and associated transmission is currently determined solely by the load forecast for its firm and interruptible customers in Ontario. This means that the requirement is not based on:

- the export of primary or secondary power to other provinces;

- the export of primary or secondary power to the United States (except for some minor firm sales for border accommodation); and

- the sale of secondary power to customers in Ontario.

However, Ontario Hydro is prepared to consider primary and secondary sales to other provinces and the United States, if this will work to the advantage of its primary customers in Ontario and can be shown to be in the general interest of the people of Ontario.

Ontario Hydro does purchase primary and secondary energy from other provinces and secondary energy from the United States, where this is to the advantage of its primary customers in Ontario.

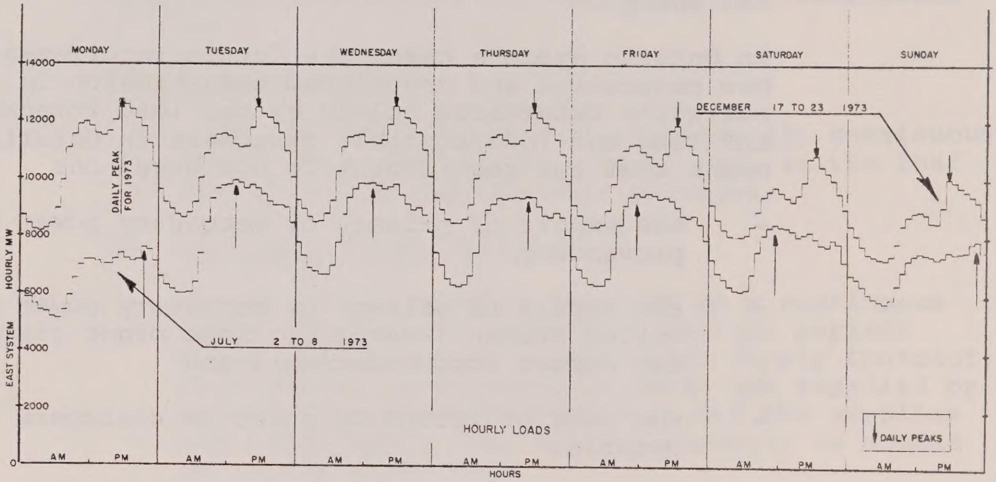
B. Load Characteristics

Ontario Hydro's load arises from hundreds of diverse uses:

> Water heaters, milking machines, household lights, blenders, chick brooders, mixers, saws, radios, tvs, furnaces, washers, dryers, refrigerators, stoves, floodlights, streetcars,

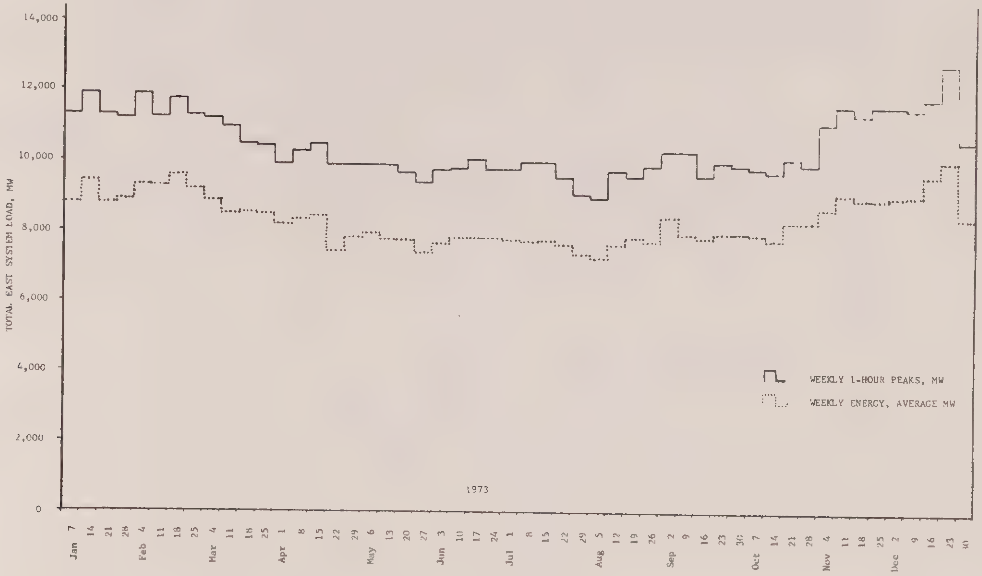
boring mills, grinders, rolling mills, electrochemical equipment, etc.

The patterns of use of the different devices are very diverse. However, their combined use results in total loads on the generating system which have relatively orderly patterns.



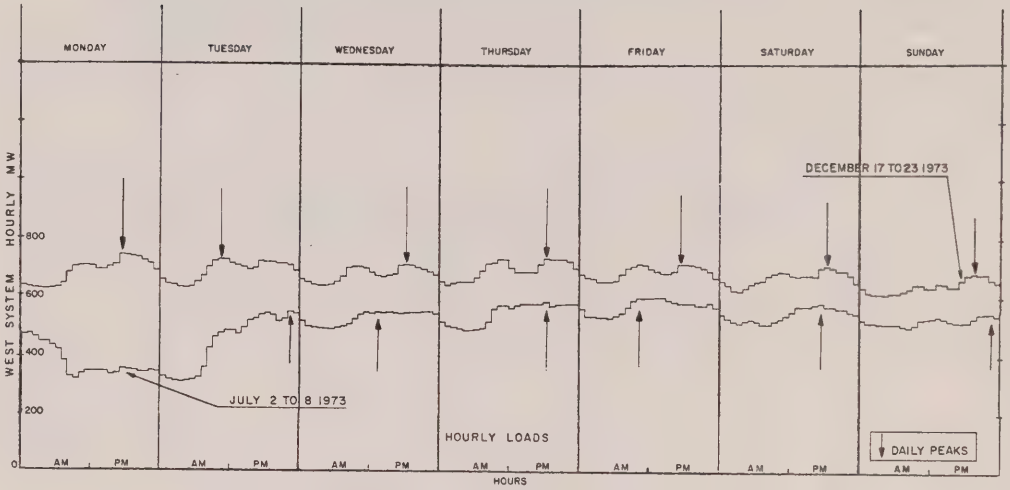
This figure shows the clock-hour load over a December week and over a July week for Ontario Hydro's East System. In both seasons the load is highest in daytime and lowest in nighttime and on weekends. The summer load is lower and has a flatter shape during the daytime. Winter daily peaks tend to occur in the hour from 5 to 6 pm, whereas those in the summer tend to occur at almost any hour in the day from 8 am to 6 pm.

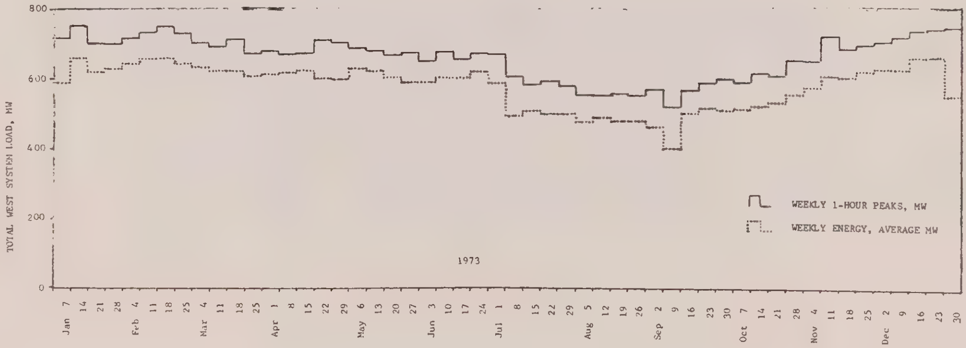
The load patterns change in other months of the year and also may change from year to year. The following figure shows the peak loads for each week and the energy, or average load, for each week throughout a year.



Summer loads are substantially lower than winter loads.

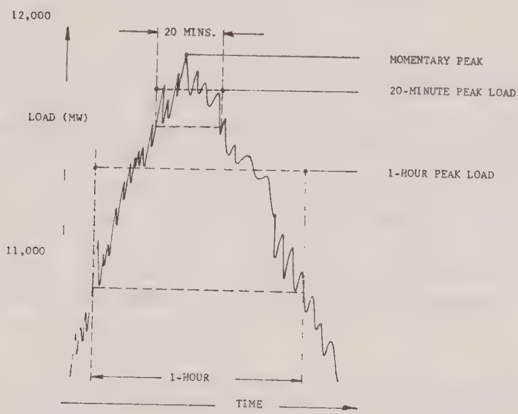
The corresponding data for Ontario Hydro's West System are shown below:





The West System daily loads are much flatter and the nighttime loads are relatively much higher than they are on the East System. The West System load pattern throughout the year shows less seasonal variation than the East System. The pattern on the West System reflects its very high content of paper and mining loads which, when their markets are high, tend to operate on a continuous basis throughout most of the days of the week. When their markets are low, these companies tend to operate at high levels but to shut down for more days in the week.

Within any hour, the load is not constant as shown in the preceding figures but varies from instant to instant after the fashion shown below.



Planning of the system must provide for meeting the momentary peak load. However, for statistical purposes, peak loads may be reported on a variety of bases, namely, in terms of momentary peak, 20-minute peak (which is the average load over a 20-minute period), one-hour peak, or clock-hour peak.

The ratio of the average load to the peak load in any period is termed the "load factor." Typical values, expressed in terms of percentages, are:

	East System	West System
for a winter working day	81 - 87%	90 - 95%
for a summer working day	84 - 88%	90 - 96%
for a calendar year	64 - 67%	77 - 80%

Load factors for Ontario Hydro's West System are greater than for its East System.

The load characteristics illustrated above are those which existed with no limits on the power and energy supply. Under system emergencies, Ontario Hydro can reduce the electric load by:

- instructing customers who purchase interruptible load to stop using, i.e. cut, this load. Ontario Hydro is permitted to do this under the contracts that it has with these customers.

- reducing the supply voltage.

- appealing to users through the public media to reduce their usage of power and energy.

- deliberately discontinuing power supplies to users.

However, Ontario Hydro can restrict, prohibit, or control the use of power supplied by it only if it is so authorized by order-in-council.

C. Possible Changes in Future Load Characteristics

Over the past 15 years, some changes in load characteristics have been occurring.

On a daily basis, the loads at the peak hour have been growing at a slightly lower rate than loads at other hours in the day.

Summer and winter hourly and daily peak loads have become more sensitive to the weather; summer loads are tending to increase during warm spells due to the effect of air conditioning, and winter loads are tending to increase in cold spells due to electric space-heating.

The increased weather effect on the winter loads has been coupled with a relative decrease in the use of decorative lighting during the holiday season. These

factors have resulted in a reduction in the variation in weather-corrected daily peak loads and an increase in the possibility of the actual peak load occurring on any working day from December to mid-February. If this pattern continues, as seems likely, it will tend to increase the loss of load probability in the winter months, and may necessitate higher reserve generation margins, in order to maintain any given level of reliability.

If future electric loads are permitted to grow with no restriction, the current load patterns could be expected to continue. However, there is some possibility that the load pattern may change as a result of Ontario Hydro's proposed intensified promotion of electric energy conservation by its customers, and as a result of current proposals concerning the introduction of new programs for load management.

Intensified Electric Energy Conservation

There is some evidence that energy conservation reduces energy consumption more than it reduces the electric peak load. Ontario Hydro believes that this will apply to the intensified energy conservation program. The net effect will be to reduce the nighttime loads and the daytime off-peak loads more than the peak loads. This will:

- lower load factors;
- decrease nighttime loads more than the daytime loads; and
- result in a greater rate of load change in the early morning and late evening.

All of these factors will tend to increase problems of design and operation of system generation. They may lead to the earlier use of further energy storage schemes by Ontario Hydro or its customers.

Peak Load Management in Ontario

Peak load management may be possible to some degree as a result of promotion by Ontario Hydro, changes in billing price structures for electricity or regulations authorized by the government regarding the

characteristics, and magnitude of electric load that will be supplied.

Transferring load from one season (winter) to another (summer) has little potential advantage. This is because the lower summer load pattern now existing is used for completion of planned maintenance.

The main incentive for peak load management lies in the possibility of transferring part of the load which otherwise would exist at the time of daily peak load to other times of day when load levels are lower. The benefit arises chiefly from reducing the total generating capacity requirements (resulting in capital savings) and from using lower cost energy sources if these are available at times of lower load levels (which is not always the case).

In the summer, hourly loads throughout the 14-16 hour "daytime" period are relatively constant. Load management schemes must transfer load from this period to the 8-10 hour nighttime period or to weekends.

In the winter, hourly loads throughout the 14-16 hour "daytime" period are relatively constant except for about a 4-hour period in late afternoon which has higher loads. Load management schemes must transfer load from the late afternoon period to the remainder of the daytime period, or to the nighttime period or to weekends.

A degree of load management already exists by virtue of the power sold under interruptible contracts and by water heater control.

Load management requires expenditures by the utilities to control the process (e.g., ripple control or time of peak metering, etc), and by customers to use the changed supply conditions (e.g., heat storage schemes, changed habits or work schedules, increased production capacity and product storage, etc).

The alternative to load management is for the utility to provide generating facilities to supply peak output economically for short periods of time (e.g., hydraulic peaking units or gas turbines, etc) or to use generation that is idle at off-peak times for storage purposes (e.g., hydraulic pumped storages, thermal storages, etc).

Ontario Hydro has followed a combination of load management (interruptible contracts) and of installing peaking generation and hydraulic pumped storage. Some municipalities control water heater loads. If substantial further load management were to be undertaken immediately, with the result that the peaking hydraulic and pumped storage capacity were required to operate for longer periods of the day at reduced outputs, a significant portion of this capacity would be rendered largely useless. It might also render difficult or impossible the completion of the planned maintenance program now carried out in the non-winter months. As a result, Ontario Hydro has very limited ability to utilize load management in the next few years.

If peak load management in the winter months is successful, it will likely lead to an increase in reserve generation requirements for two reasons:

(1) It will flatten the daily load shape in the winter months. Hence any major forced reduction in generating capacity will increase the amount of energy that cannot be supplied, as compared to the unsupplied energy with the existing daily peak load pattern.

(2) It will reduce the seasonal variation in loads between the summer and winter months. As noted later, this may require an increase in reserve generating capacity to enable completion of routine planned maintenance.

In the period after 1980, substantial further load management will become feasible, provided all new generation comprises large fossil and nuclear units. Whether or not it should be adopted will depend on the outcome of further analyses which would compare the costs and advantages of load management as compared to further installation of peaking generation and energy storage. These analyses should encompass all costs and advantages to both Ontario Hydro and its customers.

D. Implications of Load Characteristics Upon the Requirements for New Generation and Associated Transmission

If there were no forced outages in any month, the following statements would apply:

(1) The total generating capacity required is equal to the sum of the peak load in the month and the generation that must be taken out of service for planned outages and maintenance outages at the time of peak load.

(2) The energy-producing capability of the generation in operation must equal or exceed the energy corresponding to the hour-by-hour loads throughout the month.

(3) Some generation must be capable of reducing output overnight and weekends, and increasing output in the morning and throughout the day to match the hour-by-hour variation in the load. This restricts the number of feasible alternatives, for the following reasons:

(a) Large fossil-steam units may be incapable of being shut down over night without seriously increasing their unreliability. It may be necessary to continue to operate them during the nighttime at minimum safe loadings which may be 15% to 25% of their maximum output. At weekend, shutdowns are practical.

(b) Under some circumstances at hydroelectric generating stations, Ontario Hydro must face the choice either of operating the stations continuously or shutting them down and wasting hydroelectric energy.

(c) At nuclear generating stations, certain minimum loadings must be held to prevent poison-out of the reactors, which could render units inoperative for 36 hours or more. Therefore, if the system could use them to produce energy for only a few hours over the weekend, they may have to be shut down for the whole weekend and other generation be used in their place.

(d) Operating large fossil-steam units at part load is inefficient due to the nature of their energy input-output relations. Therefore, for units which can tolerate a nightly shutdown, there may be a cost incentive to shut them down. On the other hand, starting and stopping units consumes energy without producing useful output.

Therefore, whether units should be shut down overnight may be affected by the cost balance between the energy consumption during their shutdown and startup process, as compared to the inefficient operation at part load. Generally speaking, it will be less costly to shut down these units over weekends but it may be costly to shut them down for only a few hours overnight.

(e) The energy input-output relations for gas turbines and certain hydroelectric turbines result in very poor part-load efficiencies; therefore, there is a cost incentive to run them at high output levels or shut them down completely.

(f) Generating units which are shut down or operating at part output must be capable of sufficiently high rates of loading and unloading to match the rate of change of the electric load, during the rapid load buildup in the morning and decline in the evening.

(g) Transmission limitations between different areas of the system may necessitate more costly operation of generating units. For example, if there is a limitation on the power flow that can be transmitted into an area, this may require operation of high cost local generation in order to supply the area load; conversely, if there is a limitation in the power flow which can be transmitted out of an area, it may be necessary to shut down low cost generation if the load in the area is not great enough to enable it to operate at its full output.

(h) Operating generation must have sufficient regulating capacity to meet the minute-to-minute variations in the load. This is necessary in order to reduce the size of the swings in power inflows and outflows over interconnections with other systems. This regulation prevents intolerable effects on the other systems and preserves interconnection capability for emergency and scheduled power flows.

(4) Planned outages (annual overhauls) are necessary to preserve the operating efficiencies of units and to reduce the number and extent of forced outages. If the seasonal variation in the load is adequate, it is possible to do planned maintenance in the non-winter months without increasing the total need for generation beyond that required in the winter months. This is impossible if seasonal variation is inadequate. In this case, additional capacity must be installed to enable completion of the planned maintenance. This results in planned maintenance extending into the winter months; that is, an increase in the reserve generation is needed in order to complete planned outages.

(5) Maintenance outages (required to repair random and relatively minor defects which do not necessitate the immediate shutdown of a generating unit) can be scheduled on weekends if weekend loads are sufficiently below working day loads. If this is not the case, it may be necessary to have additional reserve capacity in order to enable maintenance outages to be completed during the working days.

(6) The daily and seasonal load variations impose a storage problem on the input energy supply to the generating stations. This applies both to the water supplies for hydroelectric generating units, and the fuel supplies for thermal units.

(7) All generating units do not supply the same proportion of the total system load. That is, they all do not operate at lower outputs during nights and weekends when the load is low, and higher outputs when the load is high.

For most types of generating units, efficiencies decrease substantially when the units are operating at part load. This arises primarily due to their high consumption of fuel in the case of thermal units or water in the case of hydraulic units, when these units are operating at synchronous speed and zero net electric output. As a consequence, operating cost characteristics tend to favour the operation of units at high loadings whenever possible, and their complete shutdown in preference to operation at part loading. On the other hand, inherent limitations in nuclear and large thermal units currently prevent their use on

such extreme daily load cycles, i.e., operated at full output during the high load hours of the day and shut down at nights or weekends.

As a result, the design and operation of the generating system to meet the daily load variations is done by arranging to shut down those units which can be shut down and restarted without substantial cost or reduction in reliability. Nuclear units and large thermal units are designed to operate at close to full load, wherever possible, and to reduce output to minimum safe loadings at times of low system load, or to be shut down completely on weekends.

Because of these costs and operating characteristics, current practice is to design new generation to operate primarily in one of the following four modes:

(1) Base Load

This is generation which operates at full output most of the time that is available.

(2) Intermediate Load

This is generation whose energy output is produced chiefly during the daytime periods.

(3) Peak Load

This is generation whose energy output is produced chiefly during the daily peak load periods.

(4) Reserve

This is generation which is planned to be held in readiness to replace operating generation whenever it becomes unavailable for any reason. It is not unused generation.

Some of the large fossil steam units may operate initially in the base load regime and subsequently in the intermediate load and peak load regimes. If this change in operation is expected to occur, initial design must accommodate the expected intermediate load and peak load mode of operation.

All the preceding comments ignore the problem of forced outages and forced deratings of generating

units, which are unavoidable. If no reserve generation is held as protection against forced outages and deratings whenever they occur, the system will be:

- unable to supply the daily peak loads fully. The probability of such occurrences is estimated by the loss of load probability computation.

- unable to supply the energy requirements of the load fully. The probability of this occurence is estimated by the loss of energy probability computation.

The frequency and duration of failures to supply the load fully can also be computed.

The description of the computations used in estimating these factors is given in the Memorandum on Reliability Criteria and Practices.

In addition to the unreliability arising due to the equipment and its operation and maintenance, a major potential source of unreliability arises with respect to assuring adequate supplies of materials such as fuel, lubricants, heavy water, etc. The Memorandum on Fuels Supply deals with the matter of fuel supply availability and reliability.

There are many categories of reserve generation.

<u>Installed Reserve</u> equals the dependable peak capability of all the installed generation, minus the peak firm load.

- Looking to the future, one deals with <u>Forecast</u> Installed Reserve.

- Looking to the past, one deals with <u>Actual</u> Installed Reserve.

The <u>Actual Installed Reserve</u> may have the following components:

- <u>Reserve Unavailable for Operation</u>. This is generating capacity unable to operate fully because it has been forced out of service or limited in its output due to breakdown; or because it has been deliberately taken out of

service or operated at partial output in order to enable maintenance to be completed.

- Actual Reserve. This equals the dependable peak capability of the generation capable of being operated, minus the peak firm load. The Actual Reserve is generally smaller than the Installed Reserve, because for most of the time some of the installed generation is incapable of being operated. It includes:

  Operating Reserve, which is generation capable of being fully loaded within 5 minutes. It comprises two components:

  - Spinning Reserve, which is generation operating on the system under governor control at an output less than its maximum output, and which is capable of being further loaded within 5 minutes.

  - Ready Reserve, which is generation not operating but capable of being started and being loaded within 5 minutes.

  Slow Pickup Reserve, which is generation in addition to the Operating Reserve, and which is capable of producing energy in 5 to 60 minutes. It may comprise two components:

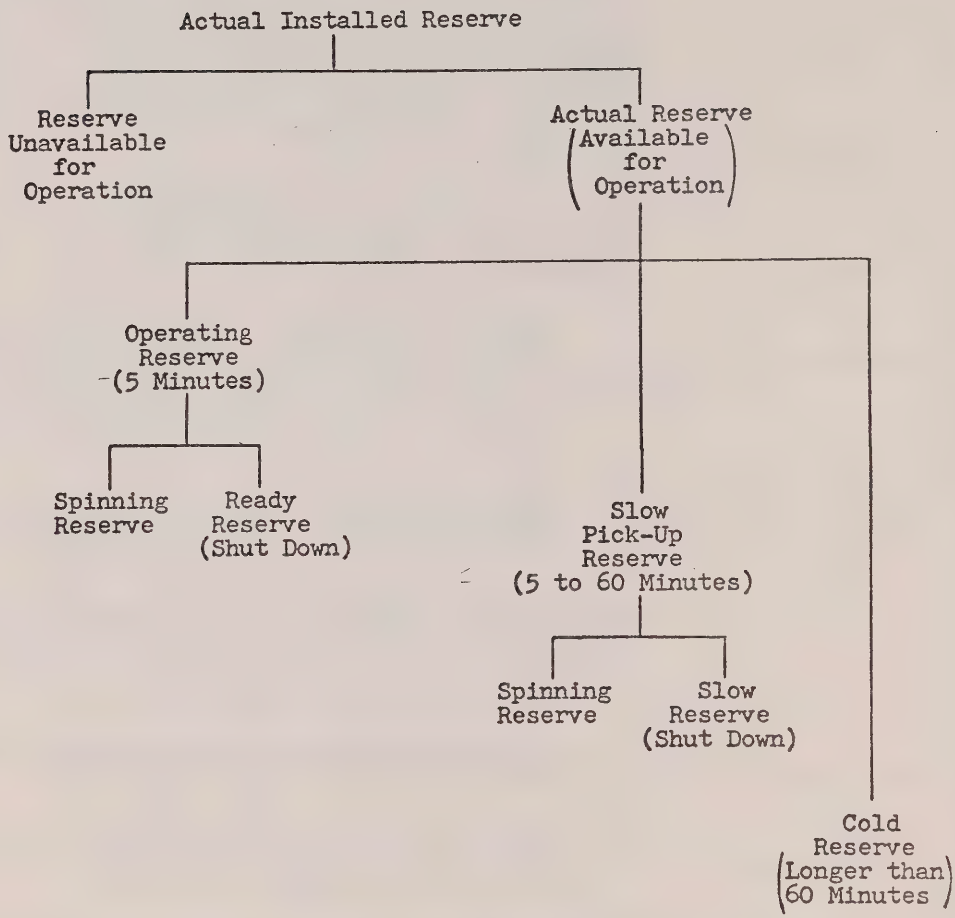
  - Spinning Reserve, which can be loaded in 5 to 60 minutes.

  - Generation which is not operating but can be started and producing energy within 60 minutes.

  Cold Reserve, which is generation not operating and requiring longer than 60 minutes to start and to produce energy.

These reserve categories are summarized below:

COMPARISON OF GENERATING RESERVES



It is desirable that the reserve generation be capable of being operated fully for long periods of time. In this way, it can provide both the peak and energy output needed to replace base load and intermediate load generation that becomes unavailable.

However, some reserve hydraulic generation may have severe limits in its capability to provide energy. This is due to limitations in water flow and water storage.

Also, some of the reserve thermal generation may be unable to provide long duration energy backup. This is due to limitations in fuel supply (which may apply to the gas turbines) or due to environmental regulations which may prevent extended operation at some stations, under some circumstances.

E. <u>The Existing Generating System</u>

The generation planning process involves forecasting the total future requirements which are discussed in Sections 11.2A, B, C, and D, deducing the part of these requirements which can be met by the existing generating and bulk power transmission system, and hence determining the requirements for new facilities.

A description of the existing generating system is given in the Memorandum on Reliability Criteria and Practices.

F. <u>Patterns of Operation of the Future Generating System</u>

Operation of the future generating system must recognize the following factors:

(1) Safety to the public and to the Ontario Hydro employees.

(2) Operation to conform with environmental constraints.

(3) Reliability of supply to customers.

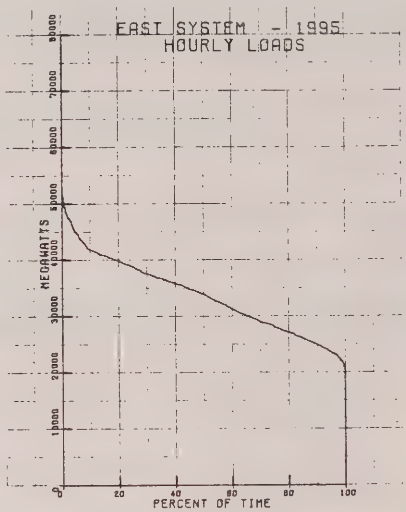
(4) Protection of electric system components from damage or excessive wear and tear.

(5) The lowest cost of energy production. Subject to the limitations arising from the above constraints, the following conditions apply:

  (a) Of the available operable generating capacity, the units which will be operated are those which will result in the lowest system cost of energy production over some stated period (e.g., a day, a week, etc). This requires consideration of the costs associated with shutting down and restarting units from time to time within the period.

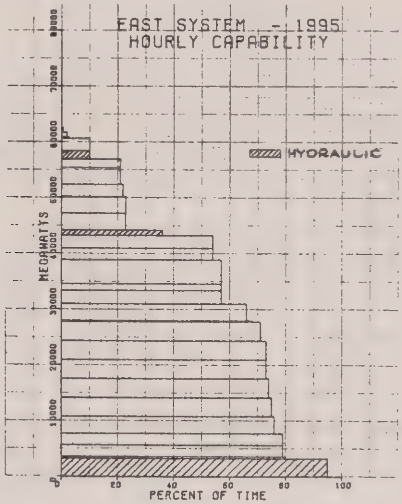
(b) Units which are actually in operation will be loaded in a specific "merit" or "stacking order", wherein the units with the lowest incremental production cost are used before those having higher incremental production cost.

The following figure shows the estimated annual duration curve of the East System primary electric load in 1995. It corresponds to the load forecast made in early 1976, and includes the effect of the intensified conservation program.



The load duration curve shows the variation in hourly loads throughout the year. The left-hand value is the highest load in the year, the right-hand value is the lowest, and the remaining loads are distributed between these values in successive order of their size. The following figure shows the estimated use of generating capacity in supplying the above loads, and

applies for the generation expansion program which Ontario Hydro is now proposing corresponding to the 1976 load forecast.



The estimated distribution of generating unit capacity factors reflects the effects of merit order loading, and also of the forced, maintenance, and planned outages and deratings which prevent any unit from operating 100% of the time in a year. The operating bands for hydroelectric capacity are coarse approximations, because in fact hydroelectric individual station capacity factors would be distributed across the range from 0% to 95%.

No unique definition of peak load, intermediate load, and base load operating regimes is used by electric utilities. Generally speaking, peak load corresponds to annual capacity factors from 0% to 10%. Base load can be defined as the band of capacity factors in the range from continuous operation every day down to continuous operation five days per week, during the time that a unit is available for operation which is about 77% for a large thermal unit. On this basis, base load corresponds to annual capacity factors from 100% to 55%, and intermediate load would fall between 10% and 55%.

From the above figure, one can deduce the following:

Operating Regime	Amount of Capacity in %	Amount of Energy in %
Peak Load plus Reserve	9.0	1.2
Intermediate Load	21.8	9.4
Base Load	69.2	89.4
	100 %	100.0%

The base load component provides the predominant part of the total capacity and of the total energy production. The cost and reliability of base load capacity is the predominant factor in determining the cost and reliability of supply of power and energy.

11.3 CONSTRAINTS

The main constraints fall in the areas of safety, environment, reliability, and cost. Some constraints are given in specific terms, but others are given in relative terms.

Examples of specific constraints are those limits set by the Ministry of Environment on atmospheric and water pollution. However, even though these are given in specific terms, they may be subject to modification from time to time.

Safety constraints are often expressed in relative terms. For example, it is impossible to specify that no Ontario Hydro personnel or the public will be injured as a result of operation of Ontario Hydro vehicles; but it is possible to specify that over some period of time, Ontario Hydro's vehicle accident record should be no worse than the general industrial rate.

Many constraints are interrelated with others. For example, if standards of reliability of electric supply are too high, they may result in power costs which customers cannot afford.

Underlying the above main constraints are many additional constraints such as:

- availability of resources, such as capital, equipment, materials, land, manpower, etc., for building and operating facilities.

- technical limitations on the alternatives available to Ontario Hydro, or on the manner in which installed facilities can be operated.

- the fundamental need for electric power by the people of Ontario, as compared to their need for other energy supplies and other essential living requirements. This sets limitations on the costs which the people are prepared to pay for electric power and energy.

- the political processes for the identification and resolution of conflicts.

The major problem is that the nature and relative weighting of these constraints are constantly changing within Ontario. The weightings are difficult to resolve for current conditions and extremely difficult to forecast for future conditions. Nevertheless, it is necessary to estimate the size and relative weightings of these factors, implicitly or explicitly, in order to reach decisions on future courses of development of Ontario Hydro's generation and bulk transmission system. Generally, decisions are reached largely by consideration of the provincial viewpoint, although this requires forecasting the influence of factors outside Ontario.

For example, the forecast of future limits on capital funds requires an overview to be made of capital availability outside Ontario, Canada, and North America. Conclusions on the forecast must take into account the competition for available funds arising from government and private sectors elsewhere in Canada.

The constraints related to safety, environment, finance, and many technical matters are treated in detail in other memoranda. This memorandum summarizes some of the discussions appearing in the other memoranda and attempts to interrelate many of the constraints.

11.4 ALTERNATIVES FOR DEVELOPMENT OF NEW GENERATION AND ASSOCIATED TRANSMISSION

11.4.1 Installation of No Additional Generation

This is an alternative which must now always be considered and judged to be unacceptable before Ontario Hydro can expect to proceed very far in the current process of public participation and the obtaining of government approval for new facilities.

It could encompass a range of alternatives such as the following:

(a) Allow some increase in load by using the current reserve capacity to supply additional load. This results in a reduction in the reliability of supply to current users of electricity and to new users of electricity, as compared to current reliability levels.

(b) Restrict current uses of electricity in order to enable new uses to be made of the existing generation and transmission.

(c) Introduce load management in order to modify the amount and pattern of use of electricity, and/or enable the supply of additional energy to new loads which exist only in off-peak load periods.

(d) Prohibit any growth in electric load.

Ontario Hydro is permitted to use promotion or special rate structures to achieve some of the above effects (a), (b), and (c); but it cannot prohibit major growth in load or enforce major changes in patterns of electric use without an order-in-council. Restrictions of this nature have not existed for many years, but they may become necessary in the future if Ontario Hydro is unable to develop sufficient new facilities.

An important consideration in any decision to halt the expansion of generation and transmission facilities is that unless the growth in electric load is also halted, the quality of service will progressively deteriorate. Thus, halting expansion in order to gain time to seek the best course of future development can have adverse effects. In addition, there is uncertainty that the best course of future development will ever be known no matter what degree of delay is inserted to enable more extensive investigation.

Unless the government and the people of Ontario at large call for a halt in growth, and to the extent that load growth cannot be met by the above measures (a), (b), and (c), it is necessary to provide new generation and transmission facilities.

Install Additional Generation

One of the initial steps in the planning process is the listing of alternative sources of power that can be developed. They fall into two categories: practical alternatives that can be committed for design and construction now, and the other alternatives which may become practical in the future. Categorization will be subject to changes as time passes. Present alternatives may become impractical and new alternatives may become feasible as a result of research and development, application, and changed conditions.

Technical advancements in the field of power generation rarely occur as rapid "breakthroughs". They are the result of a protracted process of research, design, development, and application. However, some of the yardsticks used for comparing alternatives, such as the availability and cost of capital funds and of fuels, can and do change rapidly.

The practicality of alternatives may, in some cases, be a function of the economy of quantity, of the economy of scale, and of technical maturity.

The economy of quantity of a particular device relates to the number of that device which is developed and used. For example, producing a single turbogenerator can be expected to result in a much higher cost per unit than producing 30 identical turbogenerators. This is related to the spreading of the costs of design and development, and manufacturing facilities among more units.

The economy of scale is related to the effect of increasing the size of a particular device. For example, the capital cost per kilowatt of a 500 MW fossil-steam generating unit is much lower than that of a 200 MW unit of similar type. The economy of scale arises due to a better utilization of labour and materials.

Technical maturity results from the application of the lessons learned from a history of practical design, construction, and operation. It may take many years for a completely new type of device to reflect the effect of application of these lessons.

All alternatives for new power sources are discussed in detail in the Memoranda dealing with Generation - Technical and System Interconnections. The practical alternatives that can be committed for design and construction now are discussed in the following items A to H.

The nature and timing of Ontario Hydro's use of such alternatives will be affected by the extent to which load growth and future load characteristics are altered by load management, conservation, and restriction in the usage of electricity by present and future customers.

A. Interconnections

These can be used to supply load growth in any combination of the following three ways:

(1) By providing reserve capacity, and thus making available some of the existing reserve capacity for use in supplying load growth. This has several disadvantages:

(a) Reliability of reserve capacity from interconnections is expected to be poor because of inadequate future levels of reserve in other utilities.

(b) The use of reserve capacity from other utilities is subject to restrictions that may be imposed by other jurisdictions, such as the National Energy Board in Canada, and the Federal Power Commission in the United States.

(c) The cost of energy production from reserve capacity tends to be very high because of the nature of the capacity normally provided to fulfill this function (gas turbines or overload ratings of fossil-steam turbines).

(d) Reserve capacity, by its nature, may be limited in its energy-producing capability (gas turbines and hydroelectric peaking capacity). Long duration supplies of energy assistance are unlikely to be available.

(e) Estimates of the availability of power and energy assistance in the planning period 10 to 14 years ahead are subject to great uncertainty.

(2) By enabling diversity exchanges. The extent of daily diversity exchanges by Ontario Hydro appears to be very limited because of Ontario Hydro's relatively flat daily load shape and the energy-producing limitations of its gas turbines and hydroelectric peaking capacity. A potential exists for seasonal diversity exchanges, wherein Ontario Hydro could deliver some power to utilities in the United States in the summer months when their peak load occurs, and receive power from them in the winter months when Ontario Hydro's peak load occurs. The feasibility of such seasonal diversity exchanges depends entirely upon Ontario Hydro having sufficiently large reserves in its winter months so that it will have excess capability in the summer months even after conducting routine maintenance on its large thermal units. The converse also applies, that is, that United States utilities must have sufficiently large reserves in the summer months to enable them to deliver power to Ontario during the winter months.

Diversity exchanges suffer from the same disadvantages enumerated under (1). One way to reduce the uncertainty associated with such exchanges is for Ontario Hydro to confine its transactions to short-term sales of surplus power during the summer months. However, this does not provide power and energy assistance in the winter.

(3) By enabling firm purchases. For example, it may be possible to arrange firm summer purchases from a winter peaking utility, and firm winter purchases from a summer peaking utility, in this way attaining year-round firm power.

Alternatively, it is possible to purchase firm year-round power as a result of a neighboring utility advancing construction of a new generating station. Ontario Hydro has purchased and will continue to purchase firm year-round power, whenever this is to the advantage of its primary power customers.

Major purchases of firm power from neighboring utilities are unlikely to arise in future years. When they will arise is unknown and it will depend on the year-by-year course of development undertaken by neighboring utilities. In laying out long range plans for the future development of generation and transmission, Ontario Hydro's practice is to assume that no major purchases of firm power will be made. If and when such purchases are made, it is unlikely that they will be of sufficient size to cause a substantial change in Ontario Hydro's program for developing generation in Ontario.

B. Conventional Hydroelectric Generation

Section 2.2.1.1 of the Memorandum dealing with Generation-Technical discussed this subject and outlines the current estimate of Ontario's remaining conventional hydroelectric potential in the larger developments, which are shown in Figure 11-2.

Many of these sites are capable of economic development as low capacity factor installations which could operate for only a few hours per day. The energy available from such plants is small relative to Ontario's requirements for new sources of electric energy.

Only one major conventional hydroelectric energy source remains undeveloped. This is the complete development of the Albany River, together with major diversions of the Winisk and Attawapiskat Rivers and rediversion of the Ogoki River into the Albany River. The power potential is about 3000 MW. The energy

potential of this scheme is about 2100 average MW, i.e., roughly similar to that from a single 3000 MW nuclear or fossil-steam generating station.

Only preliminary engineering and economic studies of this Albany River development have been completed. They indicate the development may be too costly, compared to nuclear or fossil-steam generating capacity. But major additional studies involving engineering and environmental matters and public participation would be required to determine whether studies or development should proceed and whether approval could be obtained. Ontario Hydro has not yet decided whether or not it will proceed with further studies on this project. If the development were to proceed, it is unlikely that it could be brought into service before 1990. At best it might replace one 3000 MW fossil or nuclear station. However, it could have a major effect on the development of high voltage transmission between the East System and the West System, and on the future development of generation in the West System. It would also have an effect on or be affected by the development of a trans-Canada transmission network.

Reviews of the potential hydroelectric capacities listed in Figure 11-2 will be made from time to time and sites will be proposed for development if their cost is attractive and they will serve a useful purpose on the system.

In addition to the larger potentials listed in Figure 11-2, there are many smaller potential developments. These include some which were once developed as small hydroelectric installations or sources of mechanical power which have been shut down for many years for various reasons. Ontario Hydro has no active program to examine the development of the small sites. Earlier work indicates that it is unlikely that many of them will be sufficiently low in cost for development by Ontario Hydro under present conditions.

<u>Location</u>

The location of a hydroelectric generating station is limited largely by natural conditions of topography, geology, and rainfall. Some degree of flexibility is possible by use of water storage developments, water diversions, tunnels, and canals, etc.

Capital

Because the nature of a hydroelectric station varies greatly from one site to another, it is not possible to state typical capital costs for hydroelectric developments. Generally speaking, the capital costs per kilowatt are lower for large installations, and those possessing the large heads. Capital costs tend to be high relative to those of large fossil-steam generating units; and because the remaining sites tend to be in remote locations, they must carry the burden of additional transmission costs and power and energy losses.

Operation and Maintenance

Operating and maintenance costs tend to be low, compared to large fossil-steam generating units.

Input Energy

The input energy is derived from natural water supplies and the head which can be developed. Natural water supplies tend to be highly variable, but they are renewable. Water supply is not free because the province of Ontario levies water rentals on the use of water at hydroelectric stations.

Peak Reliability

The mechanical and electrical reliability of hydroelectric capacity is high, but the reliability of peak power production may be adversely affected by changes in water supply and wind, and by ice formation.

Energy Reliability

This is affected by the variation in water supply and wind, and by ice formation. It is of considerable concern for systems containing a large proportion of hydroelectric capacity, as in the case of Ontario Hydro's West System at present. It is of lesser importance when hydroelectric capacity is a small part of the total capacity.

Load Cycling

Hydroelectric capacity can be started and stopped, and loaded and unloaded quickly. Therefore, it is

excellent for following the night-to-day and weekend load variations.

Part-Load Operation

Part-load operation is generally satisfactory; however, some units have very poor efficiency at low loadings. For this reason and because of the good starting and stopping characteristics of the units, operating practice on large systems is to run the units at high loadings or shut them down completely when they are not required to meet the load.

Operating Regime

Because of their good operating characteristics, each unit can be designed and operated in any of the operating regimes, i.e.: base load, intermediate load, peak load, or reserve. Cost considerations generally determine the regime for which any site is developed.

C. Nuclear Generation

The Memorandum on Generation-Technical discusses the several alternative nuclear reactor systems which are available and outlines the factors considered in Ontario Hydro's continued installation of CANDU-PHW reactors.

Continued installation of new CANDU-PHW reactors carries with it the need to ensure adequate supplies of heavy water.

In the period up to 1995 for the East System, nuclear generating unit sizes most likely to be used are 500-600 MW units similar to the Pickering GS units, 750-850 MW units similar to the Bruce GS units, and 1250 MW units which have been under preliminary study in recent years. The larger unit sizes of up to 2000 MW may become feasible towards the end of the period, but these have not been studied in detail.

For this period, in the West System, smaller units of 200-300 MW or 500-600 MW would be considered if no major addition is made to the capability of the transmission system interconnecting the East and West Systems. If a major addition is made to this capability, larger units would be considered.

Location

For the purposes of planning generation in the period up to 1995, it is assumed that nuclear units would be located outside densely populated areas. To reduce the transmission requirements and associated power and energy losses, they should nonetheless be located as close to load centres as possible.

Other factors affecting siting requirements are discussed in Section 6.5 of Reference 11-(1). To the extent possible, it appears preferable to locate these stations on the shores of the Great Lakes and the Ottawa and St. Lawrence Rivers so that their waters can be used for cooling.

Capital

Capital cost per kilowatt of the generating unit itself is substantially greater than that of a fossil-steam generating unit. However, the difference in capital cost is reduced substantially if account is taken of the associated cost of mining, transporting, and treating fossil fuels.

Operation and Maintenance

These costs tend to be in the same order but somewhat higher than the costs of fossil-steam generating units.

Input Energy

The CANDU reactor uses natural uranium at present, but in future may be converted to using plutonium or thorium cycles. The supply availability and reliability of these fuels is discussed in the Memoranda on Generation-Technical and Fuels Supply. The energy production cost from nuclear units is much lower than that of fossil-steam units.

Peak Reliability

Peak reliability of CANDU nuclear units is estimated to be similar to that of fossil-steam units of corresponding size.

Energy Reliability

The energy-producing reliability of nuclear units is expected to be similar to that of fossil-steam units of corresponding size. The reliability of supply of input energy is estimated to be higher for nuclear than for fossil fuels.

Load Cycling

CANDU nuclear units as now designed are capable of rapid shutdown and startup. However, a major limitation in shutdown and startup arises due to inherent limitations in the reactor which can result in the unit poisoning out and thereby being unavailable for up to 36 hours under some circumstances. For instance, this can occur if after a rapid shutdown from full load a unit is not reloaded to high load levels in a short period of time (typically from 20-40 minutes).

The onset of and the resulting duration of poison-out is a complex relation depending upon the rate of unloading and reloading of the reactor. It is dependent upon reactor design. With the CANDU reactor design now used by Ontario Hydro, operation at full load during the daytime with a scheduled overnight shutdown is impossible, but nighttime outputs can be lowered to about 50% of the daytime. On weekends the units can be operated at lower power levels or shut down completely on a scheduled basis.

Part-Load Operation

Because of the above load-cycling characteristics, and the low cost of energy production from the CANDU nuclear units, it is planning practice to assume these units will operate continuously at high loads if possible. However, it is also considered that overnight reductions to 50% loading and weekend shutdowns will be used if necessary.

Operating Regime

It is assumed that CANDU units installed up until 1985 will operate at base load in their initial years of operation. Eventually, these units and later units will be operated at reduced output overnight if system operating pattern so demands; i.e., they will contribute both to the base load and the intermediate

load capability of the system. Alternatively, it may prove possible to operate them continuously at base load, providing excess electric or thermal energy at nighttimes and perhaps on the weekends which will be used in energy storage devices -- for example, hydroelectric pumped storages or district-heating storages.

D. Fossil-Steam Generation

The Memorandum on Generation-Technical describes the alternative fossil-steam generation systems that are available. Broadly speaking, the alternatives relate to the type of fuel (high or low quality coal, residual oil, and gas) and to the quality of the steam supplied to the turbogenerator (supercritical or subcritical).

The Memorandum on Generation-Technical states Ontario Hydro's conclusion that, after completion of the oil-fired stations at Lennox and Wesleyville, no new fossil-steam stations should be committed to the use of residual oil or natural gas. Therefore, for planning purposes, it is assumed that all new fossil-steam stations after Lennox and Wesleyville will be fuelled by coal.

Supercritical units and subcritical cross-compound units are available in the range of unit sizes up to about 1300 MW. Subcritical tandem units, which would be the right choice for intermediate load operation, are available up to about 900 MW.

Location

The Ministry of the Environment's guidelines respecting air quality probably would prevent major new coal-fuelled fossil-steam units from being installed within a densely populated city at present. This limitation may eventually be overcome, if practical and reliable methods become available for treating coal before it is fired in the boilers or for treating the products of combustion, so as to meet the guidelines. For the purposes of planning new generation up to 1995, it is assumed that large fossil-steam generating stations will be located outside densely populated areas. As with nuclear stations, fossil-steam stations should be located as close to load centres as possible, and on the shores of the Great Lakes or the Ottawa or St. Lawrence Rivers.

Capital, Operation and Maintenance

For the purposes of this discussion, these costs for other alternatives are related to the costs for fossil-steam generation.

Input Energy

Vast supplies of coal are available in North America, but their reliability of supply may be poor and their costs high, for the reasons discussed in the Memorandum on Fuels Supply. The long term reliability of supply of Western Canadian coal should be good once experience has been obtained on supply agreements and logistic systems.

Peak Reliability

The mechanical and electrical reliability of fossil-steam units and nuclear units in meeting peak loads is much poorer than that of hydroelectric units.

Energy Reliability

The energy supply reliability reflects not only the reliability of the units but also the reliability of the fossil fuel supplies.

Load Cycling

Small fossil-steam units, operating at lower temperatures and pressures are capable of rapid loading and unloading, and of overnight shutdown without serious reduction in reliability. Large units operating at high temperatures and pressures are less able to stand high rates of loading and unloading and overnight shutdown without a reduction in reliability. One means for accommodating the above shortcoming is the installation of a steam bypassing system which enables better control of the boiler at part-load, and better control of temperatures of steam entering the turbogenerator during the starting process. The improvements due to such an installation are not well-established.

Part-Load Operation

The alternative to shutting large fossil-steam units down overnight is to reduce their loadings to minimum safe values in the overnight period. Minimum loadings

are below the 50% value that applies to the present CANDU nuclear units used by Ontario Hydro. However, operation at part-loads for extended periods is very inefficient.

Operating Regime

Supercritical fossil-steam units would normally be operated only in the base load regime. They could meet or better the 50% nighttime loading and weekend shutdown pattern provided by CANDU nuclear units. Subcritical fossil-steam units are best operated at the base load or intermediate load regimes, but can also provide peak load or reserve. Intermediate or peak load operation would probably be achieved not by shutting them down overnight but by operating them at minimum safe load.

E. Gas Turbine Generating Units

Gas turbine engines are available in a wide range of sizes, from under 5 MW up to 100 MW. Larger sizes of gas turbine generating units can be devised by using two or more gas turbine engines to drive a single generator.

Gas turbine units can have a simple thermodynamic cycle, which is inefficient, or a more complex and hence a more efficient cycle.

Gas turbines suffer from the fact that their output and efficiency decreases significantly as the ambient air temperature rises. Therefore, their capability is much lower in summer months than in winter months. A particular advantage of the gas turbine units is that they do not need cooling water supplies.

Location

Provided clean fuels are available and adequate silencers are provided, gas turbines can be located within densely populated areas. They may be located by themselves, or associated with transformer stations and thermal generating stations. When located at thermal generating stations, in addition to providing peak capacity to the system, they may be used to provide power for shutting down or starting up the thermal generating station in emergencies.

The major problem of gas turbine units is their use of premium fuels, i.e., light distillate oils or natural gas. An advantage is that they can be located closer to the point of use, and hence may possibly reduce the amount of transmission and voltage control equipment required.

Capital

Capital costs per kilowatt tend to be much lower than for fossil-steam generating units.

Operation and Maintenance

Operating staff requirements are much lower than for fossil-steam stations, but depending on the type of operation and fuel used, maintenance cost may be higher.

Input Energy

The preferred fuel is natural gas and the next preferred is light distillate oil. These are premium fuels because of their low pollution problems and their high use for other purposes. As a result, their cost will be high and their reliability in times of regional or national fuel shortages will be low.

Peak Reliability

Reliability of units operating relatively continuously and using natural gas is good. For intermediate operation and using distillate oil, it tends to be poor.

Energy Reliability

The energy-producing reliability of gas turbine units suffers from the peak reliability deficiencies and the problems of unreliability of fuel supplies. To overcome the latter, an extremely large storage of fuel may be required.

Load Cycling

Gas turbine units are not as flexible as hydroelectric units but are more flexible than nuclear and fossil-steam units. They can be started up and shut down on relatively short notice and shut down overnight as

required. However, frequent starts and shutdowns increase their costs of maintenance.

Part-Load Operation

The part-load characteristics of single gas turbine engines tend to be very poor. Therefore the operating practice is to run them close to continuous load or shut them down. Some units are capable of short-time peak outputs in excess of their continuous load. Operation in this mode tends to increase their maintenance cost.

Operating Regime

Under Ontario Hydro's conditions, gas turbines are used primarily as reserve capacity, peak capacity, or as standby capacity at generating stations for shutting down and starting up thermal units in emergencies.

F. Combined Gas Turbine and Steam Turbine Generating Units

The combination of these units compensates for the poor efficiency of gas turbine generating units by using the high temperature combustion gases which they normally exhaust to the atmosphere to produce steam in a boiler. This steam is then used to drive a conventional steam turbogenerator to produce power in addition to the power generated by the gas turbine units. The combined cycle installation may produce power at a slightly higher efficiency and about the same capital cost per kilowatt as a conventional fossil-steam generating unit. Some questions on the practical value of the combined cycle and its reliability must await operating experience on installations which have been recently put into service.

The chief disadvantage is the need to use premium fuels in order to operate the gas turbines. Another disadvantage is the need for cooling for the conventional steam turbines used.

Ontario Hydro studied the use of combined cycles and concluded it is unlikely to be advantageous because of its requirement for premium fuels.

Location

The location is more difficult than for gas turbines alone because of the need to provide cooling water to the conventional steam turbines. However, if premium fuels and cooling water can be obtained, installations could be made in densely populated areas.

Capital

The capital cost per kilowatt of the combined cycle installation is of the same order of that for a station comprising large conventional fossil-steam units, but some savings may arise due to reduction in transmission and voltage regulating facilities.

Operation and Maintenance

Costs of operation and maintenance are probably in the same order as those of the conventional fossil-steam generating stations using large units.

Input Energy, Peak Reliability, Energy Reliability

These items are similar to those for gas turbine generating units. The high cost of distillate fuels more than offsets the higher efficiency of these units compared to fossil-steam coal-fuelled units.

Load Cycling

These units are not as good as gas turbines for load-cycling duty but are better than conventional large fossil-steam units.

Part-Load Operation

Part-load operation is more efficient than for a gas turbine, particularly if several gas turbines are used to produce steam.

Operating Regime

Combined cycles are suitable for operating on base load, intermediate load, or peak load duty. The cost of fuel supply will determine the operating regime for which they will be planned.

G. Dual-Purpose Thermal-Electric Generating Units

The types of dual-purpose thermal-electric generating units most likely to be constructed in the period up to 1995 are those which serve as incinerators of refuse as well as electric power producers, and those which produce useful heat in addition to electric power.

These units may be owned and operated by Ontario Hydro, individuals, industries, or municipalities. To the extent that they are developed, they may reduce the power and energy that Ontario Hydro will need to produce in its large central thermal generating units which are designed and operated solely to produce electricity. For the planning of the large central generating stations up to 1995, the question is to what degree will such dual-purpose units be developed.

If refuse is burned in the boilers of Ontario Hydro's large central fossil-steam generating units, or if it is used by others to produce heat for process or district-heating purposes that would have been developed in any case, this will reduce Ontario's requirements for fossil fuels but by a relatively small amount. However, it will not reduce the electric load that Ontario Hydro must meet from its large central generating stations.

If refuse is used to produce electricity in small local stations, it will reduce the power and energy which Ontario Hydro will need to generate in its large central generating stations. However, the total amount of refuse available will not produce a large amount of electricity. The effect on Ontario Hydro's requirement for large central generating station and transmission will be small. These sorts of installations may be developed so as to rely upon backup electric capacity provided from the main Ontario Hydro system. To the extent that they do rely on this backup, there would be an effect on Ontario Hydro's need for reserve capacity and transmission.

A somewhat larger reduction in the forecast of Ontario Hydro's need for large central generating stations could arise if there were substantial installations of dual-purpose units designed to burn fossil fuels and produce electricity as well as heat for district-heating or process-heating by industry. This would be the case whether the installations were made by

Ontario Hydro or others. It would affect Ontario Hydro's need for large central generating stations, for two reasons: Firstly, it would produce electricity on a local basis; and secondly, it would reduce the electricity consumed for electric space-heating and process-heating.

It is, therefore, necessary to consider the extent of which dual plants producing electricity and heat might be installed on a local basis. There are some obstacles:

(1) To achieve practical schemes, it is necessary to obtain a franchise for the supply of heat which will prohibit the use of gas, oil, or electricity for major new space-heating within the district-heating area.

(2) The heat load must be built to high consumption levels quickly, in order to reduce the period of part-load operation of the capital facilities. (This is not a serious factor in multiple space-heating installations by gas, oil, or electricity.)

(3) The dual-purpose generating stations must meet environmental regulations. This probably will require use of high-cost premium fuels. Because the long-term supply of these fuels may be in question, high billing rates may be necessary in order that rapid recovery of capital costs through revenues can be assured. Alternatively, some form of extensive government subsidy or insurance may be required.

Process-heating schemes, often associated with the production of electricity, always have been and will continue to be installed by industries if they are economic. District-heating schemes may also become economic for new communities. The effect of such schemes as they develop will automatically taken into account in Ontario Hydro's ongoing load forecasting process, and hence in its planning of new generation and transmission.

A concept recently proposed would be the location of industries using large amounts of process heat in "industrial parks" adjacent to a major Ontario Hydro station for process-heating. This would require a major coordination of future industrial development,

possibly involving the Ontario Government, to ensure that adequate industrial process-heating load would be available to make the concept economic. The design of Ontario Hydro's facilities would require close coordination with the design of the industrial process heat scheme. One major difficulty in such coordination is the fact that the lead time for industrual development is much shorter than that for developing the Ontario Hydro facility; another is the uncertainty in the expected life of certain industrial processes.

H. Energy Storage Schemes

No practical large scale means exist for storing and recovering electric energy directly. Therefore, if excess capability for producing electric energy exists, it must either be left unused or used by conversion of the electricity to storable forms of energy. The Memorandum on Generation-Technical discusses these possibilities in Section 2.2.8. In the period up to 1995, the most likely schemes appear to be associated with the storage of excess nuclear energy produced at nights and weekends, by using it:

(1) electrically, to drive hydroelectric pumped storage schemes which can be used to produce electricity during the high load periods of subsequent working days. This would increase the electric load during the pumping periods, but it would not reduce the primary electric load at other times. Instead, it would provide another means of meeting the primary electric loads. Hydroelectric pumped storages have traditionally been located above ground. But proposals are under study for underground installations.

(2) electrically, to charge thermal storage systems which can be discharged for space- or process-heating during subsequent periods. Such schemes would increase the electric load during the charging period and could potentially decrease primary electric energy generation which might otherwise be used to provide these heating requirements during daytime periods.

(3) electrically, to charge batteries or flywheels for subsequent use as motive power for vehicles. This would increase the electric load during the

charging periods, but would not decrease primary electric loads during the daytime periods.

(4) in the form of heat at nights and weekends, which is stored for subsequent use during daytime periods for district- or process-heating, or boiler feedwater-heating in the nuclear station itself. This would not increase the electric load at any time, but might reduce the electric space-heating and process-heating load during daytime periods.

The cost advantage of such schemes will depend primarily on the existence of excess nuclear generating capacity at nights and weekends, which is unlikely to occur before 1990. These and other schemes will be kept under review and employed when they become advantageous. Their effect on electric generation requirements will automatically be taken into account in Ontario Hydro's ongoing load forecast process.

I. Summary of Alternatives

Figure 11-1 gives a general summary of the alternative large-scale sources of power that can reasonably be considered for the Ontario Hydro system up to 1995, with the exception of combined cycle units and dual-purpose thermal electric stations.

Figure 11-2 gives the estimate of Ontario's remaining conventional hydroelectric potential in the larger developments.

Figure 11-3 gives information on some aboveground pumped storage sites.

Figure 11-4 summarizes some information on commercially available thermal generation equipment.

J. Sites for New Central Thermal-Electric Generating Stations

The number of sites available in Ontario for development of new large central thermal electric generating stations is potentially large. Ontario Hydro's past practice has been to acquire a number of sites and hold them in readiness for development as

the need for specific new generating stations arose. This provided a measure of diversity on the location of each generating station when the time for release came due. Ontario Hydro would prefer to continue this past practice. It has not been able to do so in recent years because of some concerns of the ministries of the government and of the public. Hence, Ontario Hydro's ability to acquire a sufficient number of acceptable sites for future purposes is not clear.

The probable maximum capacity in the period up to 1995 of approved thermal generating station sites now owned by Ontario Hydro is discussed below.

A judgment as to the "Probable Maximum Capacity" of a site is influenced by factors such as physical, environmental, regulatory, legal, technological, and cost constraints, and public acceptance. These factors change from location to location and from time to time.

<u>R.L. Hearn</u>

The first four 100 MW units will have completed 30 years of service by 1983, however, their usefulness for peaking service or reserve is likely to continue beyond that date. In their present condition, these units can only burn natural gas.

The changing energy and economic climate may indicate the redevelopment of these generating units for the supply of district heating or for heat recovery from refuse, providing that such schemes become practical. Either use is likely to require greater fuel consumption than at present; and this may have to be in the form of coal rather than gas.

The last four 200 MW units will have completed 30 years service in 1991. These units are efficient, and are likely to be used for low capacity factor generation and for peaking and standby service well after 1995. They can burn both natural gas and coal.

Depending on the availability of alternative sites and associated transmission rights of way, it may be necessary to partially redevelop the site with larger and more efficient turbine-generator units.

If natural gas and/or low (1/2%) sulphur (Western) coal is available for power generation, it may become possible to replace the existing four 100 MW units by two 500 MW units, and still meet current regulatory standards. This would require extensive modification to the present cooling water circuit.

J.C. Keith

The four coal-fired units at this station which have a combined capacity of 264 MW, will have completed 30 years service in 1983. The lifetime of these units will depend on the modifications they will require within the next few years to continue operating. The plant has a number of problems including those of foundation, emission control, and high cost.

It would appear that any redevelopment of the site would be directed toward the supply of district heating or heat recovery from refuse, if these systems become feasible and desirable. Both of these processes may require a considerable increase in the amount of fossil fuel consumed by the plant.

Lakeview

With its present eight 300 MW coal-fired units, the Lakeview site has been fully developed and no additional generating capacity is likely to be installed before 1995. Following the Watts from Waste Demonstration at this station in 1978, it may continue to be used to burn refuse in additional to coal.

Lambton

Industrial emissions, particularly SO_2, are of considerable concern in the Sarnia Chemical Valley. However, if stack emissions and discharge of waste heat can be kept to acceptable levels and fuel oil is available, the Ontario Hydro property has potential to accommodate up to two 750 MW oil-fired units, in addition to the existing four 500 MW coal-fired units.

Nanticoke

The Nanticoke site will be fully developed when the present construction of eight 500 MW coal-fired units is completed.

Lennox

After completion of the four 500 MW oil-fired units now under construction at Lennox GS, there will remain a potential for two additional stations on the Ontario Hydro property. Of these additional stations, both could be nuclear, or one could be nuclear and the other fossil-steam. Current land use plans show part of the site allocated for a fish hatchery. If the fish hatchery is developed, then the fossil-steam station would need to be oil-fired as there would be insufficient room for a coal storage pile.

It has been known for some time that the waters of Lake Ontario at Lennox are a fish spawning ground. Thus, any future increase of generation on the site, will probably require extensive cooling water intake and discharge facilities in order to prevent undesirable thermal effects on the lake in this area.

Wesleyville

In addition to the projected four 500 MW oil-fired units at Wesleyville GS, an additional nuclear station could be built on the west half of the site.

Pickering

With the construction of Pickering GS "B", the site will have been fully developed to its ultimate capacity of eight 500 MW nuclear units.

Bruce

In addition to the 200 MW Douglas Point nuclear station, Ontario Hydro's current generating facilities under construction and planned for the site, i.e. Bruce "A" and Bruce "B", comprise eight 750 MW nuclear units. The property presently owned would permit the development of two additional stations which could be either fossil-steam or nuclear.

However, extensive investigations and monitoring of the possible effects of the installed and planned facilities will be required to establish whether the site could support additional generating capacity. It is envisaged that extensive studies on cooling systems and transmission would be required.

Darlington

In addition to the planned Darlington GS of four 850 MW nuclear units, the currently held property will permit development of two additional nuclear stations or one nuclear station and one coal-fired station. These would be subject to investigations and studies of the effects of the planned nuclear station and considerable new analysis of air quality if a fossil-steam station were proposed.

Thunder Bay

The present capacity is one 100 MW coal-fired unit, and two lignite-fired units of 150 MW each are scheduled for completion in 1980 and 1981. The site could accommodate an additional 600 MW. However, under current pollution control regulations, increased operational restrictions are expected.

11.5 COMPARISONS OF ALTERNATIVES

11.5.1 General Comments

All alternatives must be satisfactory with respect to the safety, reliability, environment and cost constraints. Alternatives are not equal in all factors. In principle, one would like to be able to assign some common means of quantifying and weighting all the diverse factors, and hence be able to compute for each alternative a composite socioeconomic measure of its total value, and cost. In practice this proves to be impossible at the present time, because no generally accepted method yet exists for quantification and weighting of the different factors. Therefore, the present practice of comparing alternatives is to quantify internal costs and external socioeconomic costs, where possible, and use judgment in the weighting of other externalities, as described in Section 4.1 of the Memorandum on Socioeconomic Factors.

In addition to the above dominant factors, the following ones should also be considered:

A. Flexibility

This encompasses both operating flexibility, and flexibility to meet unpredictable future conditions.

Operating flexibility is the ability to change output rapidly, to operate at low outputs, and to shut down overnight and on weekends. These matters are discussed in Section 11.4.

Flexibility to meet unpredictable future conditions might include the ability of a thermal generating unit to use alternate fuels, and to operate on loading patterns greatly different than those for which the unit was designed. Most fossil-steam units can burn only a small range of alternative fuels. This is because their capital cost must be increased substantially if they are designed to use a wide range of fuels; cost analysis indicates that it may be less costly to rebuild a boiler to meet a future major change in fuel than to spend larger initial sums of money to design the boiler initially for use of a wide range in fuels. CANDU-PHW nuclear units could be converted to use plutonium and thorium, with no major modification cost.

Both large fossil-steam and CANDU-PHW units have potential problems if they are operated on a highly cycled loading pattern. If changing conditions of future loads and generation tend to increase the cycling and to decrease annual capacity factors, the solution might be the introduction of energy storage schemes which would result in meeting cycling requirements and at the same time would preserve high annual capacity factors on the large thermal units.

On the other hand, hydroelectric and gas turbine peaking units are highly vulnerable to circumstances which increase generating unit capacity factors. As noted earlier, load management schemes which reduce the sharpness of the winter daily peak loads and flatten the daily load shape could render such peaking units largely obsolete.

B. Obsolescence

Obsolescence may arise due to the operating inflexibility of certain types of generating capacity, as noted above. It may also arise due to the existence of new forms of generation, whose overall cost is lower than the incremental cost of existing generation. This has been the case for some of the very small hydraulic projects which have been taken out of service and abandoned.

Obsolescence may arise due to more severe regulations on environmental emissions, as has happened at Keith GS in Windsor. Retrofitting and alterations may provide such a plant with an extension to its useful life.

Generating equipment is generally designed and subsequently operated and maintained, on the assumption that it should provide a satisfactory long useful life. For accounting purposes, gas turbine, fossil-steam and nuclear generating units are assumed to have useful lives of 30 years; but large fossil-steam and nuclear units can probably be maintained in useful form for longer periods than 30 years. Useful lives of hydroelectric stations in Ontario are generally expected to be more than 50 years.

C. Generating Unit Reliability

As noted in the Memorandum on Reliability Criteria and Practices, it is not yet possible to specify the optimum system reliability on the basis of overall socioeconomic costs. Therefore, present practice is to set an arbitrary target level of generating system peak reliability.

Different types of generation may have different degrees of reliability. However, regardless of these differences, the aim of the planning process is that all alternatives should enable the generating system to supply the peak load with the target reliability.

Therefore, the comparison of alternative forms of generation requires account to be taken of the different amounts of peak generating reserves that they require. This process can be undertaken by probability computations.

However, account must also be taken of the reliability of energy supply to the customers. The energy-producing reliability of the generating units depends on both their mechanical and electrical reliability, and also on the reliability of their input energy supplies, i.e., water supply, coal, gas, oil, uranium. The mechanical and electrical reliability can be computed by probability methods. The assessment of the reliability of input energy supplies is based largely on judgment; but it is of major importance in the comparison of thermal-electric alternatives. Ontario Hydro's judgment is that the relative order of

reliability, from best to worst, is: nuclear fuel, coal, residual oil, distillate oil and natural gas.

D. Transmission

Where they are significant amounts, account must be taken of the differences among alternatives with respect to total transmission requirements and the associated power and energy losses.

E. Timing

There are at least two aspects to the subject of timing. The first is the fact that the list of alternatives that are available and practical for development may change as time passes, new alternatives being added, and former alternatives deleted. The second is the matter of lead time -- the time required in order to bring a new facility into commercial service. The lead time may vary from one alternative to another. Also, for a given project the lead time quoted depends on its stage of development, i.e., whether or not a site has been acquired, whether or not the site development studies have been completed, whether or not project approval has been obtained, etc.

For a major new thermal-electric generating station, the following periods in years are representative:

	Nuclear 850 MW Units	Fossil-Steam 750 MW Units	Fossil-Steam 200 MW Units	Combined Cycle
- Investigations and public participation culminating in approval to acquire a specific site.	2-3	2-3	2-3	2-3
- Specific site investigations and public participation and preliminary engineering culminating in project release.	3	3	3	3
- Site preparation	1-3	1-3	1-3	1-3
- Detailed design and on-site construction, up to in-service date of the first generating unit.	5½	4½	3½	3½
	11½-14½	10½-13½	9½-12½	9½-12½

Thus, lead time constraints may themselves eliminate from consideration those alternatives which cannot be brought into service by the time that new facilities are required. Also, to ensure that the full range of alternatives can be available, it is necessary to reach decisions on starting the site acquisition process as long as 14 years before the estimated date that major new generating facilities are required.

These long lead times themselves impose significant constraints on the planning process. Ontario Hydro is investigating methods of reducing them.

11.5.2 Illustrations of Some Specific Comparisons

A. Introduction

This section illustrates many of the factors discussed above, particularly those related to reliability, and internal costs, for the following types of generation:

- CANDU-PHW nuclear
- Fossil-Steam, coal-fuelled
- Gas Turbines, oil-fuelled

Costs of hydroelectric generating sources may vary widely from one installation to another.

All the cost data given in this section relate to generating stations comprising four units of identical size. For such stations, the cost per kW and costs per kWh are lower than for stations comprising one or two units.

All the costs for the fossil-steam units are based on using United States coal. The costs shown are known to be too low because they do not include:

- the capital cost of facilities for cleaning stack gases or the cost of facilities for treatment of the delivered coal, that will be needed if the stations are to meet future air quality regulations.

- the additional cost of operating, maintenance and materials needed, and the additional power and energy consumed due to this stack-gas cleaning and/or coal treatment.

As a result, all the comparative data developed in this section show the cost of the fossil-steam plants to be lower than they would be in practice.

The net costs for interim storage and long term disposal of spent nuclear fuel are not expected to be significant and are not included in the cost data for nuclear units.

B. Reliability

Figure 11-5 shows the forecast made in 1975 of new generating unit outage indices for use in studies of future system development. This type of forecast is made each year.

The forecasts for fossil-steam units do not reflect the decrease in reliability that would result if special fuel treatment or exhaust gas treatment is later installed to meet air quality criteria more severe than current criteria.

The forecast for nuclear and fossil-steam units reflects the use of an extensive reporting scheme on the unreliability of existing units. No such scheme is maintained by Ontario Hydro for its hydraulic units.

C. Capital Costs

Capital cost is defined as all the costs for material, equipment and labour needed to design, construct and commission a project including overheads and interest on funds spent on this work up to the actual in-service date.

Figure 11-6 shows the estimated capital costs on three bases:

- No escalation, all costs of material, equipment and labour in terms of 1976 prices.
- Escalation included, for stations with their first units coming into service in 1985.
- Escalation included, for stations with their first units coming into service in 1995.

In the latter two alternatives, escalation rates are those forecast by Ontario Hydro in 1975.

The Figure shows that the capital cost per kilowatt of nuclear units is substantially greater than that of fossil-steam units of the same size; and the capital cost per kilowatt of the latter is substantially greater than that of gas turbines.

The percentage relativity of the total estimated capital costs per kilowatt is almost unchanged by escalation; but the dollar differences between alternatives increase as a result of escalation.

The Figure also indicates the economy of scale, i.e., the manner in which costs per kilowatt decrease as the size of units is increased. The advantages of economy of scale progressively diminish as unit sizes are

increased. Extrapolation of the figures indicates that the economy of scale will eventually disappear for nuclear units at some size greater than 2000 MW, and for fossil units greater than 750 MW.

D. Operating and Maintenance Expenses

Figure 11-7 shows the estimated normal annual operating and maintenance expenses per kilowatt, excluding fuel, for 1976. It also indicates the economy of scale: larger units have lower costs per kilowatt. Costs for nuclear units are higher than those of fossil-steam units of similar size (this is in part due to the cost of heavy water make-up and upgrading for the nuclear units).

E. Energy Production Expenses

These are the costs of the input fuel consumed per kilowatthour of electricity generated. For 1975 conditions, they are estimated at:

1.27 mills per kWh, for CANDU nuclear units, 500 MW and larger

10.26 mills per kWh, for fossil-steam units using US coal, 500 MW and larger

25.20 mills per kWh, for gas turbine units

It is estimated that these costs will continue to escalate in the future, and account of this is taken in the remainder of this section.

F. Total Cost Comparisons

The total cost comparisons discussed in the remainder of this section encompass all the above costs, plus for the nuclear units the cost of initial heavy water requirements. Thus, the total annual costs comprise charges on capital, operation, maintenance, and fuel.

For the nuclear units, the cost of the fuel is approximated by two components: half the initial charge of the reactor which is included in the capital cost, plus the estimated equilibrium annual burnup of fuel.

The total cost comparisons for thermal generating units are given in the following figures:

Figures 11-8 and 11-9

These show the estimated total annual costs per kilowatt sent out from the generating station during its first year of operation. To simplify the Figures, costs are shown for only a few unit sizes.

In Figure 11-8, the annual cost of capital corresponds to the long-run costs. i.e., they comprise interest and sinking fund amortization equivalent to the initial capital cost over the assumed 30-year useful life of the facilities.

In Figure 11-9, the annual cost of capital corresponds more closely to levies made to the cost of power, i.e., interest, straight-line depreciation, and Ontario Hydro's statutory sinking fund.

It is apparent that, regardless of whether the figures are based on 1976, 1985, or 1995 costs, at low capacity factors combustion turbines are least costly, at mid-range capacity factors coal-fired units are least costly, and at high capacity factors nuclear units are least costly. This situation prevails whether the data are based on long-run costs or related to levies made to cost of power. Using the long-run costs leads to nuclear units breaking even with fossil-thermal units at lower capacity factors, and fossil-thermal units breaking even with combustion turbines at lower capacity factors.

Figures 11-10 and 11-11

These show the total annual cost per kilowatthour sent out. They use the data of Figures 11-8 and 11-9 but express it per kWh instead of per kW.

Figures 11-8 to 11-11 show the estimated annual costs of the stations during their first year of operation. The complete cost comparison of the alternatives must encompass all their costs throughout all the years of their useful lives. This comparison is given in Figure 11-12.

Figure 11-12

This shows the accumulated year-by-year expenditures for several alternative installations of gas turbines, fossil-steam, and CANDU nuclear stations. It shows at year zero the capital cost of the station, and the additional year-by-year expenditures for operation, maintenance, and fuel.

Figure 11-12 displays the accumulated expenditures for all the alternatives, based on 60% annual capacity factor.

The diagrams run for 30 years. The actual useful life of the alternatives may prove to be greater than 30 years.

Part I of the Figure shows undiscounted accumulated expenditures. Part II shows them discounted to the year in which the first unit comes into service. It is the latter diagrams which form the appropriate inputs for cost comparison.

Part II of the Figure clearly shows that nuclear generation leads to higher accumulated discounted expenditures in its early years of operation, but thereafter much lower accumulated discounted expenditures. In the long run, it clearly leads to lower costs than fossil-steam capacity.

All the costs shown in the preceding Figures are the costs at the generating stations per kilowatt sent out. They exclude the costs of transmission and the costs of reserve capacity. Transmission and reserve costs are relatively unaffected by whether the units are fossil-steam or nuclear, but they can be affected by the size of the units and their location in the province.

Figure 11-13

Figure 11-13 indicates in a general way the reserve generation requirements related to the use of different sizes of units. The Figure shows the effect of adding a series of units to the Ontario Hydro's East System generating stations now in-service or under active design and construction, plus the Bruce B and Darlington Generating Stations.

The Figure shows the required additional generating reserves, expressed as a percent of the additional load that can be supplied with a specified target reliability (i.e., Loss of Load Probability of 1/2400, 1/240 and 1/24) by the addition of the series of units of the same size.

The middle column of diagrams in Figure 11-13 is based on the adjusted forced outage rates shown in Figure 11-5; but it uses the "mature" rates which apply for the 4th or 5th year of operation. The outer columns of diagrams show the effects of outage rates 75% and 125% of those in Figure 11-5.

It is clear from the Figure that higher reserves are required, if:

- higher reliability levels are required (e.g. loss of load probability of 1/2400 instead of 1/24);

- higher forced outage rates are used (e.g., 125% instead of 75% of the rates estimated in Figure 11-5); and

- larger unit sizes are used (e.g., 1250 MW units instead of 200 MW).

<u>Figure 11-14</u>

Using the data of Figure 11-13 and further computations, the required additional reserves for a major series of unit additions were roughly estimated at the values shown in Figure 11-14. With such data, it becomes possible to adjust the cost comparisons given in Figure 11-12 to reflect the effect of the different reserve requirements of different units.

<u>Figure 11-15</u>

This shows, for various annual capacity factors (ACF's), the accumulated expenditures at year 30, discounted to 1985, for fossil-steam and CANDU nuclear units coming into service in 1985. Two sets of curves are included:

A: The cost expressed in dollars per kilowatt of load-meeting capability. This is the

cost adjusted to reflect the effect of the different reserve requirements of different units, as noted in the preceding paragraph.

B: The costs per kilowatt sent out of the generating stations. This is the cost unadjusted to reflect the reserve requirements.

By comparing the "A" and "B" curves one can see that the inclusion of the effect of reserve requirements diminishes the advantages of the larger units, whether they are fossil-steam or nuclear.

One can also see that the annual capacity factor has a significant bearing on the cost comparison of fossil-steam and nuclear generation.

Taking account of the reserve requirements:

- at 40% ACF, nuclear units are lower in cost than fossil-steam only at sizes above 750 MW.

- at 60% ACF, nuclear units are lower in cost above 300 MW.

- at 80% ACF, nuclear units are lower in cost above 250 MW.

- regardless of ACF, there is a clear advantage in using larger generating units, up to about 750 MW for fossil units and 1000 to 1250 MW for CANDU nuclear units.

However, Figure 11-15 is based on a LOLP of 1/2400, and AFOR's equal to 100% of the forecast values. Figure 11-14 shows that the reserve "penalty" associated with larger units becomes lower if lower LOLP's are used, and/or if lower AFOR's are used.

This illustrates in general terms the underlying factors affecting the cost comparison of alternative types of units and sizes of units. There may be substantial cost advantage in using larger units.

However, the data can only be used as a general indication of costs. In practice, more elaborate studies must be done, to include such effects as:

- sensitivity to various rates of load growth and changes in other assumptions;
- the cost of providing operating reserves whose magnitude is increased as unit size is increased;
- the cost of bulk transmission and interconnection requirements which may increase as unit size is increased;
- problems in scheduling planned maintenance;
- larger units may not match year-by-year growth as well as the use of smaller units;
- different nuclear energy-production capability of programs with different sizes of nuclear units;
- more accurate estimates of the costs and reliability of alternatives;
- the higher outage rates of generating units during their period of immaturity;
- estimates of the capability of manufacturers to provide equipment for larger sizes of units, etc.;
- externalities.

Ontario Hydro's practice has been to build a series of units of about the same size and to review from time to time the net benefits arising from switching to a larger size. When the net benefits favour a switch, another series of larger units is built. Ontario Hydro proposes to continue this practice, and switch to larger units when this is advantageous.

In recent years, Ontario Hydro has concluded that future new stations for its East System in the 1980s should comprise 500 MW and 750 MW fossil-steam units and 850 MW CANDU nuclear units. However, further cost studies may indicate that

larger nuclear units should be installed in this period. Cost analysis indicates that the nuclear units should operate largely in the base load mode, and fossil-steam units in the intermediate or peaking mode of operation.

11.6 SELECTION OF ALTERNATIVES

The final selection of an alternative answers the questions: what, how much, when, and where, for the next generating capacity and associated transmission, that must be committed now. It may imply a subsequent course of action for future developments; but this course of action is always subject to change.

The final selection is made on the basis that the alternative chosen should be the best one over the long-term future, when all things are taken into account. Section 11.5.1 indicates that the selection should be based on a total quantitative socioeconomic evaluation of the alternatives.

Ontario Hydro's current evaluation deals largely with costs to Ontario Hydro, as outlined in Section 11.5.2, and weightings of many externalities, most of which are assessed on the basis of judgment.

The possible future bases of choosing the best alternative are diverse and conflicting, as can be seen from the following partial list:

(a) Selection on the Basis of Estimated Long Run Costs to Ontario Hydro

This was formerly the primary basis for decisions made by Ontario Hydro. Judgments were made on the basis of estimated present worth of all future expenditures by Ontario Hydro.

(b) Selection on the Basis of Estimated Short-Run Cost of Power to Ontario Hydro Customers

This has been a larger consideration in recent years. It reflects accounting practices rather than the estimated long-run costs, and also reflects the effects on cost of power due to the raising of funds for capital construction through billing rates to customers. It places emphasis on estimated costs of power in the next few years, rather than the next 10 to 20 years.

(c) <u>Selection on the Basis of Estimated Limitations in the Availability of Capital Funds to Ontario Hydro</u>

This has been a dominant factor since July 7, 1975, when the Ontario Government in its mini-budget instructed Ontario Hydro to reduce its capital expenditures in the period up to 1985 by a minimum of one billion dollars, and by the Ontario Treasurer's January 22, 1976 letter to the Chairman of Ontario Hydro, wherein further reductions were required.

(d) <u>Selection on the Basis of a Particular Minimum Impact on the Environment</u>

For example, one could minimize the release of heat to the atmosphere. This includes heat which serves a direct useful purpose (i.e., at the customer's premises), and heat which reflects the tariff that must be paid to produce and deliver the useful electric energy (i.e., the energy lost during production and transmission of electric power). Another example would be the the least use of agricultural land.

(e) <u>Selection on the Basis of Conservation of Energy</u>

This is concerned with reducing the amount of useful energy consumed, and with the efficiency in the processes of producing useful energy. The aim is primarily directed to prolonging the useful life of non-renewable mineral sources of energy, thus preserving them for future use.

(f) <u>Selection on the Basis of Least Use of Fossil Fuels</u>

This is concerned with reducing the amount of fossil fuels burned, and hence preserving these materials for chemical and transportation uses, instead of electricity production. It is also concerned with reducing the effect of fossil fuel combustion upon the biosphere. This target would encourage use of nuclear energy.

(g) <u>Selection on the Basis of Conservation of All Resources</u>

I.e., capital, goods, labour, land, fuels, and all other materials.

From items (a), (b), and (c), it is evident that recently used criteria for selection may conflict with one another; and they are in a changing state with (c) being dominant at present, in the eyes of the provincial government. In this respect, it should be noted that the estimated limitations in capital are specified on the basis of limitations to the Province of Ontario in the short term; and no limits on capital expenditures external to Ontario are specifically identified. This has significance, when one recognizes that capital expenditures on nuclear stations provide facilities mostly in Ontario; but expenditures on coal-fuelled stations in Ontario imply major capital expenditures outside Ontario for mining, treatment, and transportation of coal. The capital expenditures on coal appear in Ontario Hydro's analysis, not in the form of capital but in the form of annual fuel costs.

It is also evident that in present circumstances, the issues raised by item (d), (e), (f), and (g) are not paramount, although they may become so in future years. However, it is appropriate that within any primary constraints, such as capital availability, one should attempt to select the alternative which best accommodates all the other factors of concern.

Views on matters such as these are often conflicting and subject to polarization: People or groups with strongly held views have difficulty accepting other viewpoints.

There are available mathematical modelling techniques for identifying so-called "optimum" alternatives, for any given set of constraints, and provided the nature and effects of major variables can be identified and quantified. The present great uncertainty on the nature and effects of constraints and variables seriously reduces the value of such techniques as guides for judgment on decision making. Of particular concern are:

- The time-related costs of many factors may not follow the costs implied by use of the

traditional present worth discounting technique. This technique places greater weight on near-term costs as compared to long-term costs. As such, it seems to contradict concerns with respect to conservation of materials and fuels, which emphasize the long term rather than the near term.

- The effects of the conservation ethic, of load management programs, of consumer response to higher costs of energy, of population growth, etc, raise doubt not only about the rates of future growth in load, but also about the future load characteristics.

- The interrelation of competition for available capital funds, in terms of its effect on growth of the Ontario economy and hence of the Ontario electric load.

- The overall advantage to the Province of Ontario of the energy supply security from developing nuclear generation as compared to coal-fuelled fossil-steam generation.

- The difficulty in obtaining timely and final government approvals for new projects, and the uncertainty concerning the relative likelihood of obtaining approvals for competing alternatives such as nuclear or fossil-steam generation.

11.7 Ontario Hydro's Current Proposed Generation Development Program Up to 1995

11.7.1 Basis of Selection of Ontario Hydro's Proposed Program

A. Ontario Hydro believes the dominant question to be resolved at present is the nature, timing, and magnitude of future generation that will be developed to supply base load. It has concluded that to meet the system requirement for base load, it should for many years develop CANDU-PHW units at as high a rate as is feasible within the constraint of capital available to it. But it recognizes that if further major constraints are placed on its capital expenditures, it may become necessary to develop less nuclear capacity and more fossil-steam capacity.

B. Ontario Hydro believes that the next fossil-steam units to be developed should be coal-fuelled units

similar to those it has been developing, i.e., high efficiency subcritical units. Such units will provide maximum flexibility in meeting additional base loading if there is a deferment in the development of nuclear capacity, and in meeting increased lower capacity factor operation if they should be required to do so. To the extent that supplies of Western Canadian coal at reasonable cost can be assured, this fuel should be used to provide a large part of the increase in its forecast fuel requirements in the next 10 years.

C. Further major commitments to use of oil or gas should be avoided, if possible, due to their relative scarcity and cost.

D. Most new nuclear and fossil-steam generating stations should be large central power stations located adjacent to major bodies of water. However, smaller power stations with multipurposes such as electric generation, steam production for district-heating or industrial purposes, and refuse burning may become economic in certain locations; some of these may be located inland.

E. None of the new technological alternatives currently being discussed in the public domain (solar power, wind power, geothermal power, fusion, etc) are likely to have been sufficiently developed to be used as low cost and reliable generating sources to form a significant component of the Ontario power system.

F. To meet the growth in needs for reserve, peak load, and intermediate load generating capacity, and to replace fossil-steam generating units which have come to the end of their useful life, different combinations of further hydraulic and thermal capacity and energy storage schemes may be developed.

G. The only major sources of hydraulic energy remaining for development in the province are on rivers emptying into James Bay and Hudson Bay. One possibility is the development of the Albany River. This could involve 15 power dams and several major river diversions. The development of this and other hydraulic projects is likely to be affected by economic, social and environmental considerations, and provincial policy with respect to the development of renewable resources.

H. Power and energy purchase from neighbouring utilities should continue to be investigated, and arranged when they are economic or required to enable the electric load in Ontario to be met.

11.7.2 Ontario Hydro's Current Proposed Generation Development Program LRF48

Ontario Hydro makes adjustments to its Proposed Generation Development Program, whenever the need arises, as a result of changes in load forecasts, lead times, in-service dates, fuel supply problems, capital constraints, etc. For internal reference purposes, it assigns LRF (Long Range Forecast) numbers to each program. The current proposed program is LRF48. It is the program adopted in response to the Ontario Treasurer's letter of January 22, 1976 to the Ontario Hydro Chairman, concerning limitations in capital borrowings by Ontario Hydro.

Based on the capacity in Program LRF48 and Ontario Hydro's 1976 Load Forecast, modified to reflect the full effect of Ontario Hydro's intensified program on energy conservation, the attached figures give the following information on what, how much, and when:

Figure 11-16. <u>East System</u> scheduled in-service dates. The symbols E-15, E-16, etc, represent future thermal generating stations, whose sites are not yet final, on the East System.

Figure 11-17. <u>West System</u> scheduled in-service dates. The symbols W-2, W-3, etc, represent future thermal generating stations, whose sites are not yet final, on the West System.

Figure 11-18. <u>East System Load and Capacity Releations</u>
From this figure we can deduce:

- Firm load growth from 1976 to 1982 is equivalent to a constant annual rate of 6.6%.

- Firm load growth from 1982 to 1995 is equivalent to a constant annual rate of 7.0%.

- The Loss of Load Probabilities (whose significance and shortcomings are discussed in the Memorandum on Reliability Criteria and Practices). are higher than Ontario Hydro's past planning target of 1 in 2400.

Figure 11-19. West System Load and Capacity Relatio[illegible]
From this figure we can deduce:

- Firm load growth from 1976 to 198[illegible] is equivalent to a constant annual rate of 7.2%.

- Firm load growth from 1982 to 199[illegible] is equivalent to a constant annual rate of 5.2%.

- The Loss of Load Probabilities (whose significance and shortcomings are discussed in the Memorandum on Reliability Criteria and Practices) are higher than Ontario Hydro's past planning target of 1 in 2400.

Figure 11-20. East and West System Capacity. This figure summarizes the peak generating capacity provided with Program LRF48, in megawatts, and also as a % of the total.

Figure 11-21. East and West System Energy. This figure summarizes the estimated energy production under Program LRF48, in gigawatthours, as a % of the total, a[illegible] in terms of physical units. There is [illegible] planned major dependence on nuclear energy. If no new nuclear developments are installed after 1980, the total requirements for coal in 1995 would increase from the 25.4 million tons [illegible] year shown in this figure to a total of 84.5 million tons per year, an extremely large amount in terms of its effect on problems of coal supply, fue[illegible] cost, and air quality.

Program LRF48 assumes that there will be:

- no major expansion of the transmission capability between the East and West Systems. This possibility is under study, and if the transmission is expanded, the generation program in the West System would probably be changed; and

- no major new hydroelectric developments, new energy storage developments, or new power purchases from outside Ontario. To the extent that such power sources are employed, the requirements for new generation in Ontario will be reduced.

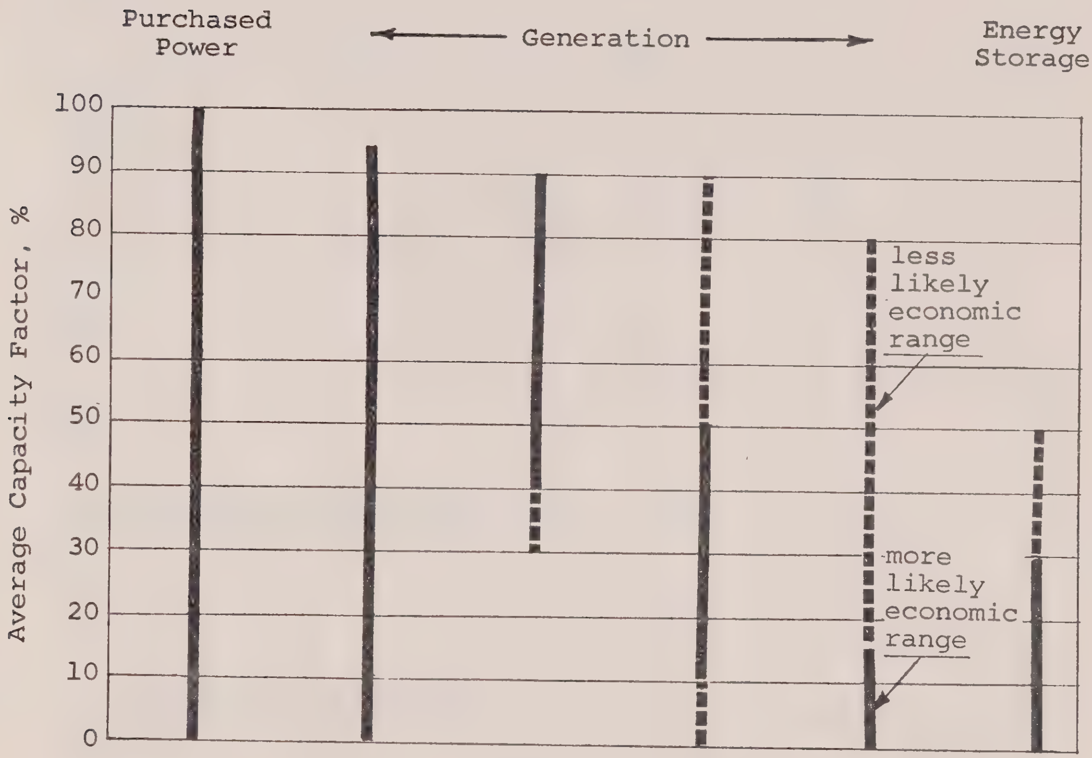
None of these figures deal with the question of "where". This matter is discussed in Reference 11-(1). As noted in Section 11.4.2J, Ontario Hydro believes it must resume its past practice of acquiring a sufficient number of new generating sites (and associated rights of way for egress), to ensure it has flexibility to meet changing future requirements and constraints. The long and uncertain time required in the present process of obtaining site and project approvals makes it essential that this work be given high priority, in order to keep open a sufficient number of alternative courses of development.

References

11-(1) Ontario Hydro. "Planning of the Ontario Hydro East System. Part I. Volumes 1 and 2" - Report Number 573SP, June 1, 1976.

FIGURE 11 - 1

Alternative Types of Power Sources That Can Reasonably Be Considered
For the Ontario Hydro System
For the Period Up to 1995



	Hydraulic	CANDU Nuclear	Fossil-Steam	Gas Turbines
Capital Cost	high	high	medium	low
Energy Cost	low	low	medium	high
Dependence on Non-Indigenous Fuel	none	low	high	high

FIGURE 11 - 1

FIGURE 11 - 2 - Sheet 1

Estimate of Ontario's Remaining Conventional Hydroelectric Potential, in the Larger Developments (Note 1)

River and Site	Hours of Peak Output (Note 2)	Estimated Increments in Peak Capacity in MW: Installed	Dependable	Average Annual Energy, in Average MW	Capacity Factor of Increment, % (Note 3)
A. NEW SITES UNAFFECTED BY ALBANY RIVER DIVERSIONS					
ABITIBI					
Long Sault Rapids	2	80	69	27	39
Nine Mile Rapids	-4 (Note 4)	128	121	66	54
	-2 (Note 4)	256	243	71	29
MATTAGAMI					
Grand Rapids	-4 (Note 5)	109	102	62	61
	-2 (Note 5)	218	190	77	41
MADAWASKA					
Highland Falls	2	95	91	16	18
MISSINAIBI					
Thunderhouse Falls	-7	13	13	10	77
	-2	42	42	20	48
Long Rapids	-7	31	31	25	81
	-2	100	100	49	49
MISSISSAGI					
Gros Cap	2	262	258	47	18
MOOSE					
Grey Goose	2	188	175	74	42
Renison	2	188	186	76	41
WHITE					
Chigamiwingum	8	16	15	14	93
Umbata	8	14	14	12	86
Chicagouse	8	11	11	10	91
B. NEW SITES AFFECTED BY ALBANY DIVERSIONS POTENTIAL ASSUMING CONTINUATION OF EXISTING ALBANY DIVERSIONS					
ENGLISH					
Maynard Falls	8	51	46	27	59
LITTLE JACKFISH					
Mileage 12.5	8	38	36	26	72
Mileage 7.5	8	46	46	33	72
C. NEW SITES AFFECTED BY ALBANY DIVERSIONS POTENTIAL ASSUMING TERMINATION OF EXISTING ALBANY DIVERSIONS (to English and Nipigon Rivers)					
ENGLISH					
Maynard Falls	N/A				
LITTLE JACKFISH					
Mileage 12.5	N/A				
Mileage 7.5	N/A				
ALBANY					
Achapi	4	131	131	33	25
Eskakwa	4	268	166	119	72
Miminiska	4	57	57	35	61
Frenchman	4	95	95	61	64
Washi	4	73	73	47	64
Kagiami	4	117	117	83	71
Martin	4	70	70	51	73
Nottik	4	73	73	55	75
Buffaloskin	4	101	101	83	82
Wabimeig	8	217	119	163	137
Chard	8	536	536	376	70
Hat	8	422	399	284	71
Blackbear	8	402	402	279	69
Biglow	8	382	382	268	70
Stooping	8	308	308	206	67
Total of Albany Developments:		3252	3029	2143	71

The above capacities presume the following diversions are made into the Albany River:
Whiteclay Diversion
Winisk-Attawapiscat Diversion

FIGURE 11 - 2 - Sheet 2

River and Site	Hours of Peak Output (Note 2)	Estimated Increments in Peak Capacity in MW Installed	Dependable	Average Annual Energy, in Average MW	Capacity Factor of Increment, % (Note 3)
D. EXTENSIONS OR REDEVELOPMENT OF EXISTING STATIONS					
Schemes Unaffected by Albany Diversions					
ABITIBI					
Canyon	2	790	714	20	3
Otter Rapids	2	175	161	4	2
MATTAGAMI					
Little Long	2	122	106	17	16
Harmon	2	136	107	18	17
Kipling	2	136	118	19	16
Smoky Falls	-4 (Note 6)	102	100	43	43
	-2 (Note 6)	157	239	66	28
MISSISSAGI					
Red Rock Falls	2-3	36	33	2	6
OTTAWA					
Otto Holden	2-3	202	156	6	4
Des Joachims	2	696	640	19	3
MONTREAL					
Hound Chute/Ragged Chute Redevelopment	2	98	98	19	19
E. EXTENSIONS OR REDEVELOPMENT OF EXISTING STATIONS					
Schemes Affected by Albany Diversions — Potential Assuming Continuation of Existing Diversions (to English and Nipigon Rivers)					
ENGLISH					
Ear Falls	8	7	5	4	80
NIAGARA					
SAB #2 (Existing Tunnels)	1/2	305	199	0	0
SAB #3 (New Tunnel)	1	458	501	138	28
NIPIGON					
Pine Portage Ext	8	27	22	1	5
Cameron Falls Ext	8	18	17	2	12
Alexander Ext	8	19	13	2	15
Schemes Affected by Albany Diversions — Potential Assuming Termination of Existing Diversions (to English and Nipigon Rivers)					
ENGLISH					
Ear Falls	N/A				
NIPIGON					
Pine Portage Ext	N/A				
Cameron Falls Ext	N/A				
Alexander Ext	N/A				
NIAGARA					
SAB #2 (Existing Tunnels)	1/2	305	199	0	0
SAB #3 (New Tunnel)	1	458	501	138	28

Note 1: The table includes new sites capable of producing 10 or more average MW. It does not include potential sites on the Severn, Winisk, and Attawapiskat Rivers because little data are available on them.

Note 2: These are the hours of operation at the dependable peak capacity that the site can provide under extremely low water supply conditions.

Note 3: The Capacity Factor corresponds to the Increment in Average Annual Energy and the Increment in Dependable Peak Capacity.

Note 4: The 4-hour peak applies if Nine Mile Rapids is developed in step with the existing generating station at Otter Rapids.
The 2-hour peak applies if Otter Rapids is extended to provide 2-hour peaking, and Nine Mile Rapids is developed in step with it.

Note 5: The 4-hour peak applies if Grand Rapids is developed in step with the existing generating stations at Little Long, Harmon, and Kipling.
The 2-hour peak applies if Little Long, Harmon, and Kipling are extended to provide 2-hour peaking, and Grand Rapids is developed in step with them.

Note 6: The 4-hour peak applies if the existing generating station at Smoky Falls is redeveloped in step with the existing generating station at Little Long.
The 2-hour peak applies if Little Long is extended to provide 2-hour peaking, and Smoky Falls is redeveloped in step with it.

FIGURE 11 - 3

Some Aboveground Pumped Storage Sites Studied by Ontario Hydro Since 1965

Site	Hours of Pumping	Hrs/Day of Generating	Generating Capability: Installed Peak Capacity MW	Generating Capability: Dependable Peak Capacity MW	Generating Capability: Ave. Annual Energy MW	Generating Capability: Annual Capacity Factor**
Delphi Point	8 hr/day+weekends	4	2912	3060	378	12
	8 hr/day+weekends	6	2000	2100	378	18
	8 hr/day+weekends	8	906	960	231	24
	10 hr/day	8	1450	1530	378	25
Matabitchuan						
- HWL 940*		8	440	429	105	24
- HWL 920*		8	234	226	56	25
Jordan-Erie	daily cycle	4	1120	1031	132	13
	weekly cycle	10.5	1120	1031	326	32
	annual cycle	(16 for 4 mos) (4 for 8 mos)	1120	1031	253	25

* HWL refers to high water level in upper reservoir.
** Based on average energy and dependable peak capacity when generating.

FIGURE 11 - 4

Commercially Available Thermal Generation Equipment

	Normal Fuel	Alternative Fuels++	Electrical Production Efficiency %	Energy Released Per Unit of Electricity Produced (a) to Cooling Water	Energy Released Per Unit of Electricity Produced (b) to Atmosphere	Maximum Unit Size MW	Most Appropriate Modes of Operation
Sub-Critical Fossil-Steam	Coal	Gas or Bunker Oil	38	1.3	0.3	900*	Intermediate or Peaking
	Bunker Oil	Gas or Crude Oil	38	1.3	0.3	"	"
	Crude Oil	Gas or Bunker Oil	38	1.3	0.3	"	"
	Gas	Bunker Oil	37	1.3	0.4	"	"
Super-Critical Fossil-Steam	Coal	Gas or Bunker Oil	39	1.3	0.3	1300+	Base
	Bunker Oil	Gas or Crude Oil	39	1.3	0.3	"	"
	Crude Oil	Gas or Bunker Oil	39	1.3	0.3	"	"
	Gas	Bunker Oil	38	1.3	0.3	"	"
Gas Turbine	#2 Oil	Gas	29	0.0	2.4	100	Peaking or Reserve
	Gas	#2 Oil	28	0.0	2.6	"	"
Gas Turbine/ Steam Turbine	#2 Oil	Gas	40	0.8	0.7	500	Intermediate or Peaking
	Gas	#2 Oil	39	0.8	0.8	"	"
CANDU Nuclear	Uranium	-	30	2.3	0.0	1250	Base

* Apparent limit on size of a tandem compound steam turbine (using a single generator).
\+ Apparent limit on size of a cross compound steam turbine (using two generators).
++ Unless a unit is specifically designed to burn alternative fuels, considerable equipment modification may be required.

FIGURE 11 - 5

1975 Forecast of New Generating Unit Outage Indices for Use in Studies of Future System Development

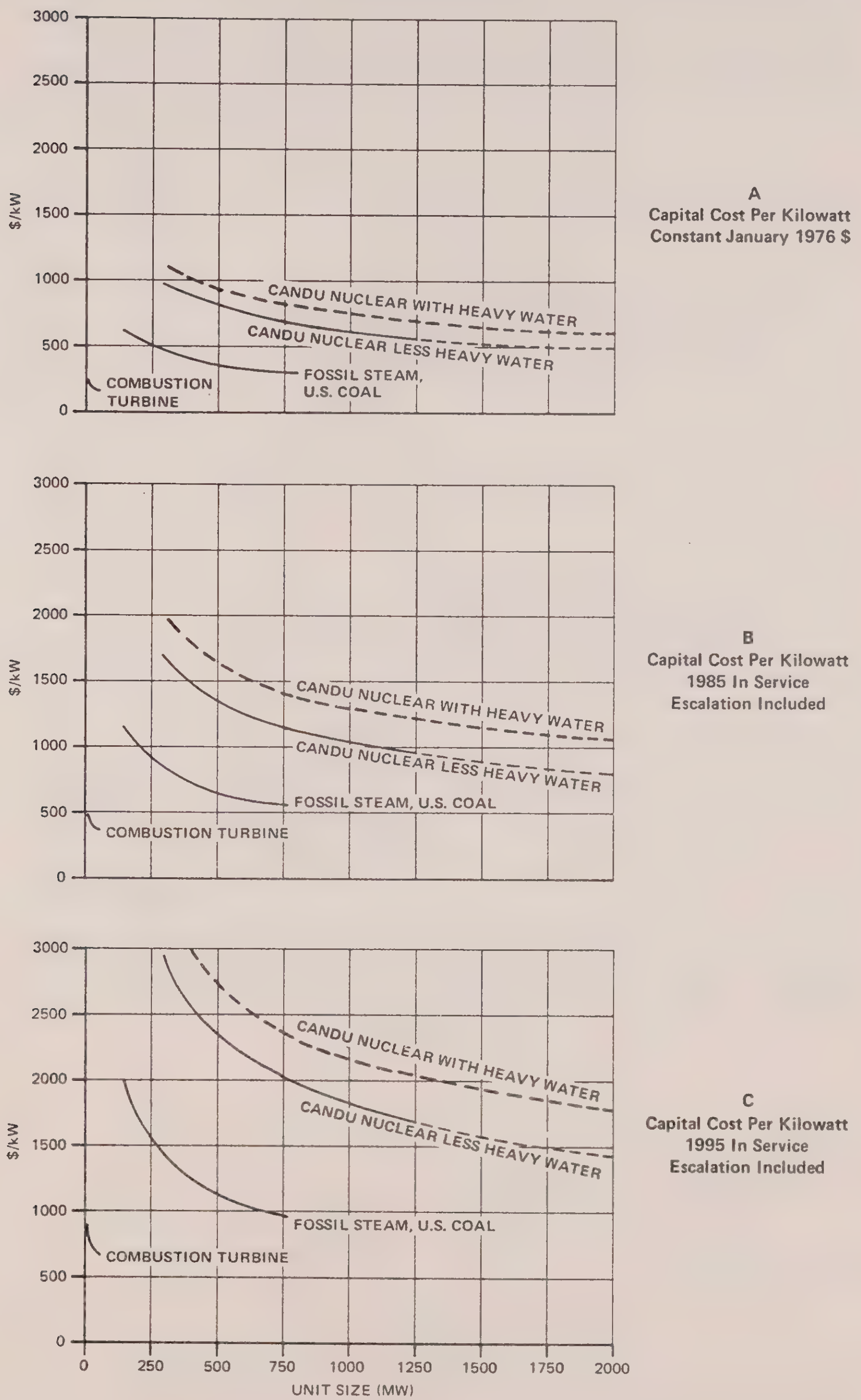
Year of Operation	1	2	3	4	5	1	2	3	4	5
	Adjusted Forced Outage Rate (AFOR), %					Maintenance Outage Factor (MOF), %				
CANDU Nuclear Units										
200	15	12	10	8	8	8	6	4	4	4
500	15	12	10	9	9	8	6	4	4	4
850	15	13	12	10	10	8	6	4	4	4
1200	22	17	15	14	12	10	8	6	5	5
Fossil Steam Units										
Lignite 150/200	15	13	11	9	9	6	5	4	4	4
Lignite 300	15	13	11	9	9	6	5	4	4	4
Bituminous Coal, or Oil 500	15	12	10	8	8	6	4	4	4	4
750	17	15	13	10	10	7	5	5	5	5
1000/1200	20	18	16	12	12	8	6	6	5	5
Combustion Turbine Units	15	15	15	15	15	(included in POF)				
Hydraulic Units	.5	.5	.5	.5	.5	(included in POF)				

Year of Operation	1	2	3	4	5	1	2	3	4	5
	Planned Outage Factor (POF), %					Capability %				
CANDU Nuclear Units										
200	12	10	8	8	8	68.0	73.9	79.2	81.0	81.0
500	12	10	8	8	8	68.0	73.9	79.2	80.1	80.1
850	14	10	10	10	10	66.3	73.1	75.7	77.4	77.4
1200	14	10	10	10	10	59.3	68.1	71.4	73.1	74.8
Fossil Steam Units										
Lignite 150/200	12	10	8	8	8	69.7	74.0	78.3	80.1	80.1
Lignite 300	12	10	10	10	10	69.7	74.0	76.5	78.3	78.3
Bituminous Coal, or Oil 500	15	12	10	10	10	67.2	73.9	77.4	79.1	79.1
750	15	12	10	10	10	64.7	70.6	74.0	76.5	76.5
1000/1200	15	12	10	10	10	61.6	67.2	70.6	74.8	74.8
Combustion Turbine Units	10	10	10	10	10	76.5	76.5	76.5	76.5	76.5
Hydraulic Units	4	4	4	4	4	95.5	95.5	95.5	95.5	95.5

NOTE: Forecasts are for units having major components supplied by manufacturers of most reliable equipment. With less reliable components, an extra 3% and 1% should be added to the AFOR and MOF.

FIGURE 11 - 6

Thermal Generation, Estimated Capital Cost
Per Kilowatt Sent—Out from the Generating Station
(4—Unit Plants)



Estimated capital costs include net cost of commissioning and for nuclear units include cost of half initial fuel.

FIGURE 11 - 7

Thermal Generation, Estimated Annual Operations & Maintenance Costs in Dollars Per Kilowatt Sent-Out at the Generating Station

These data apply for 4-unit generating stations and do not include the cost of fuel consumed in the stations. Costs are for 1976.

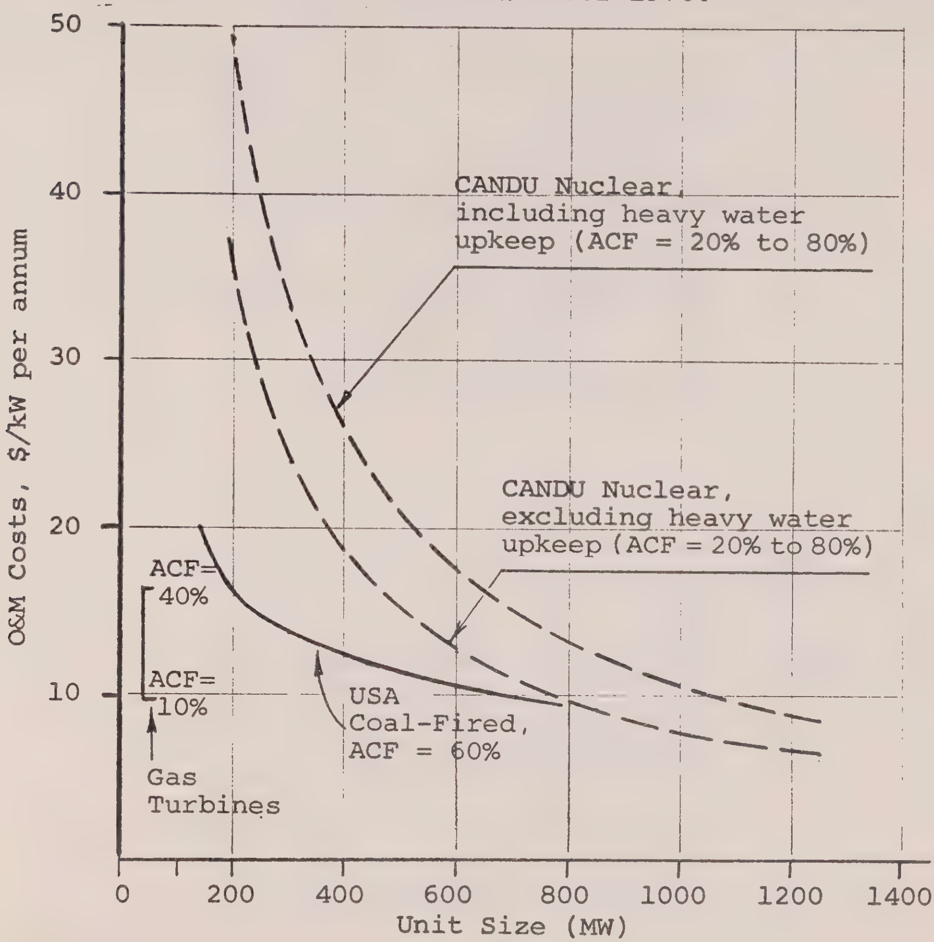
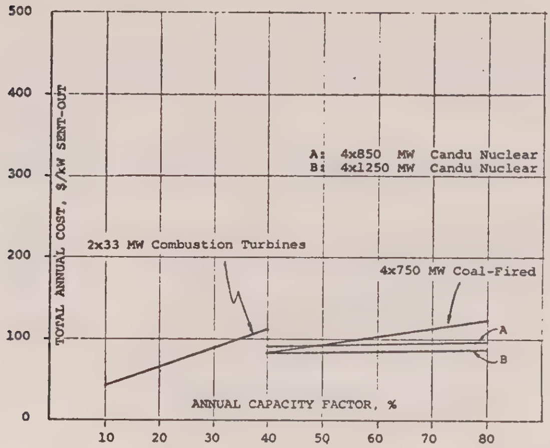


FIGURE 11 - 8

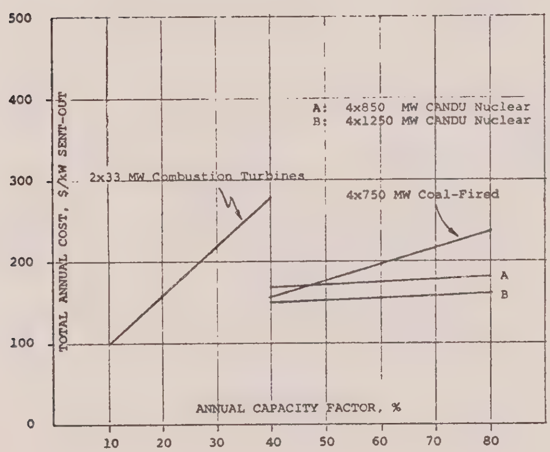
Thermal Generation, Estimated Total Annual Costs
Per Kilowatt Sent-Out From the Generating Stations

I. Interest 10%, Sinking Fund Depreciation, No Statutory Sinking Fund



1976

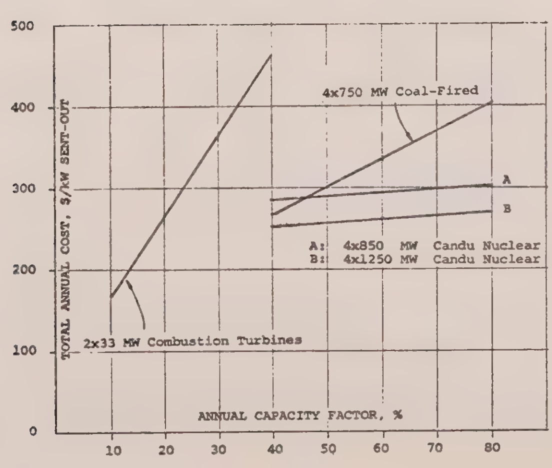
All costs in 1976 dollars.



1985

First unit in service in 1985.

Operation, Maintenance and Fuel Costs escalated to 1985.



1995

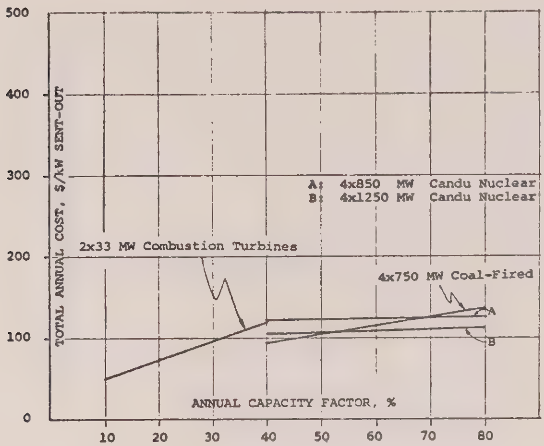
Station in service in 1995.

Operation, Maintenance and Fuel Costs escalated to 1995.

FIGURE 11 - 8

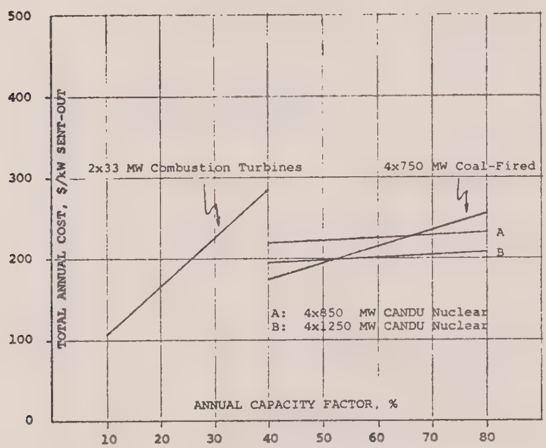
Thermal Generation, Estimated Total Annual Costs
Per Kilowatt Sent-Out From the Generating Stations

II. Interest 10%, Straight Line Depreciation, + Statutory Sinking Fund



1976

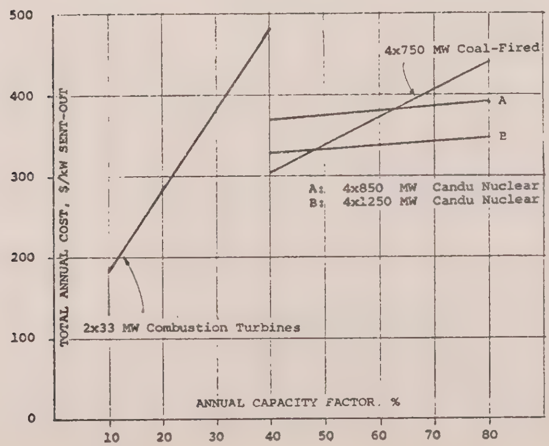
All costs in 1976 dollars.



1985

First unit in service in 1985.

Operation, Maintenance and Fuel Costs escalated to 1985.



1995

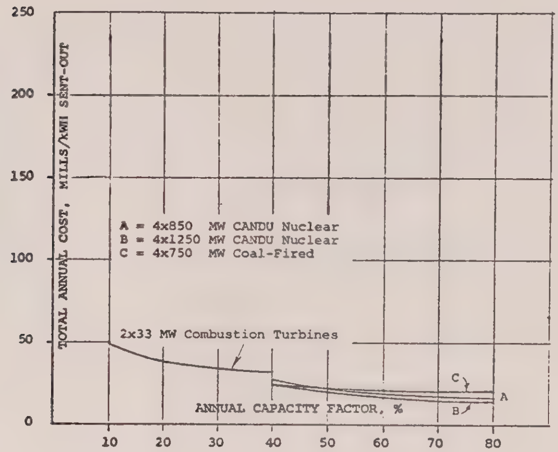
Station in service in 1995.

Operation, Maintenance and Fuel Costs escalated to 1995.

FIGURE 11 - 10

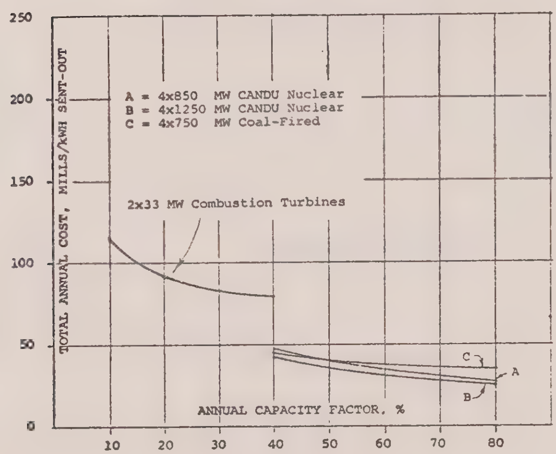
Thermal Generation, Estimated Total Annual Costs
Per Kilowatthour Sent-Out From the Generating Stations

I. Interest 10%, Sinking Fund Depreciation, No Statutory Sinking Fund



1976

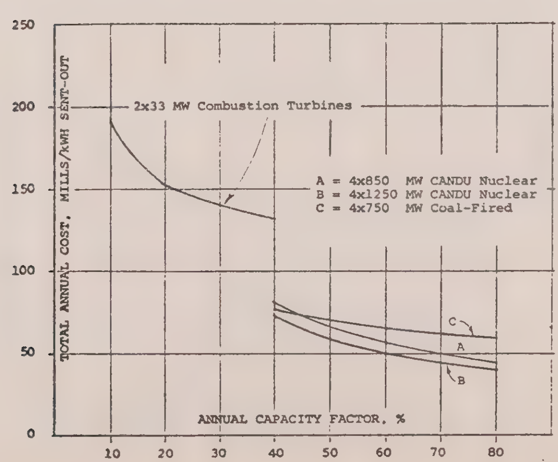
All costs in 1976 dollars.



1985

First unit in service in 1985.

Operation, Maintenance and Fuel Costs escalated to 1985.



1995

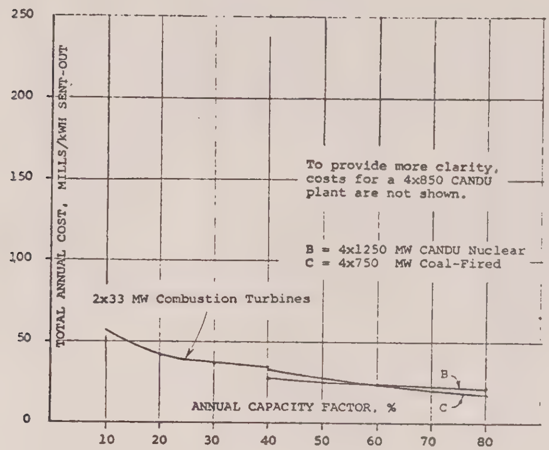
Station in service in 1995.

Operation, Maintenance and Fuel Costs escalated to 1995.

FIGURE 11 - 11

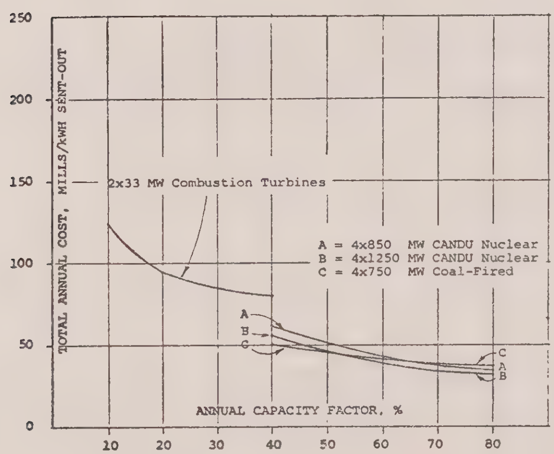
Thermal Generation, Estimated Total Annual Costs
Per Kilowatthour Sent-Out From the Generating Stations

II. Interest 10%, Straight Line Depreciation, + Statutory Sinking Fund



1976

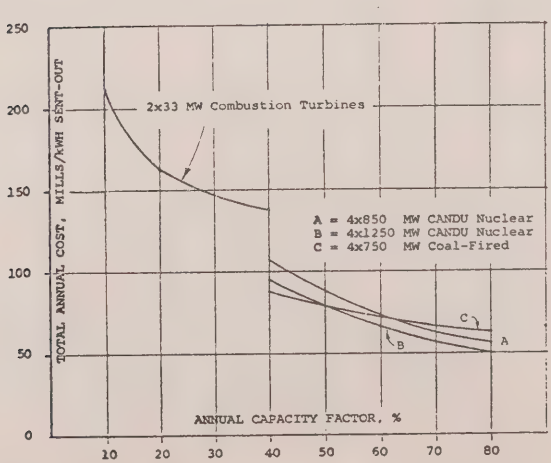
All costs in 1976 dollars.



1985

First unit in service in 1985.

Operation, Maintenance and Fuel Costs escalated to 1985.



1995

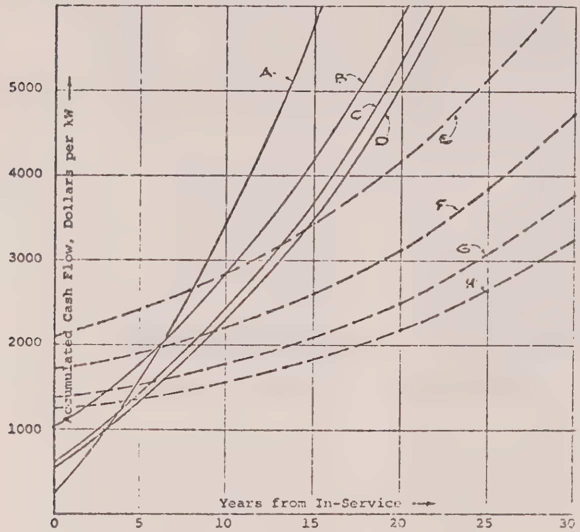
Station in service in 1995.

Operation, Maintenance and Fuel Costs escalated to 1995.

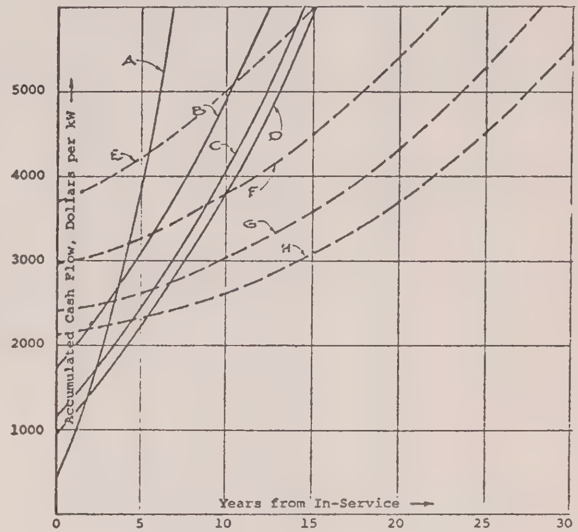
Thermal Generation, Accumulated Total Cash Outflow Per Kilowatt Sent-Out at the Generating Station (Annual Capacity Factor: 60%)

I - Undiscounted Dollars

(First Unit In-Service: 1985)

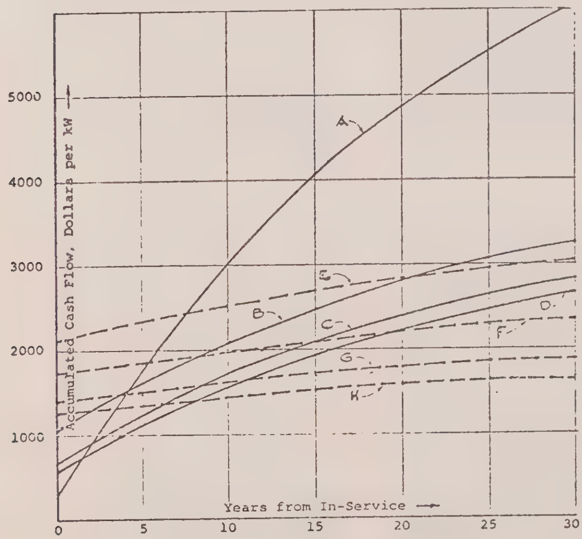


(First Unit In-Service: 1995)

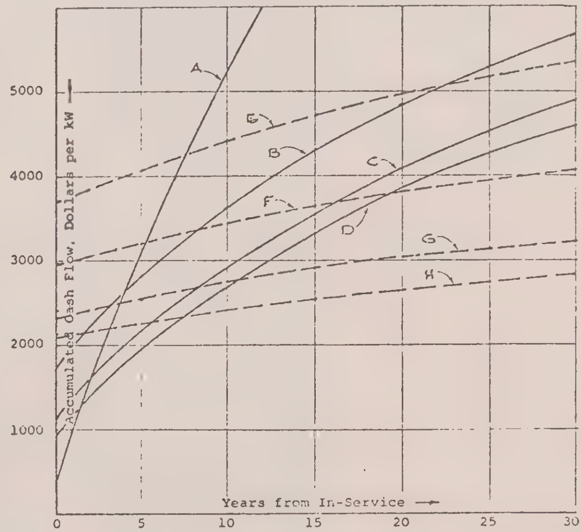


II - Discounted Dollars at 10% Per Annum

Discounted to 1985
(First Unit In-Service: 1985)



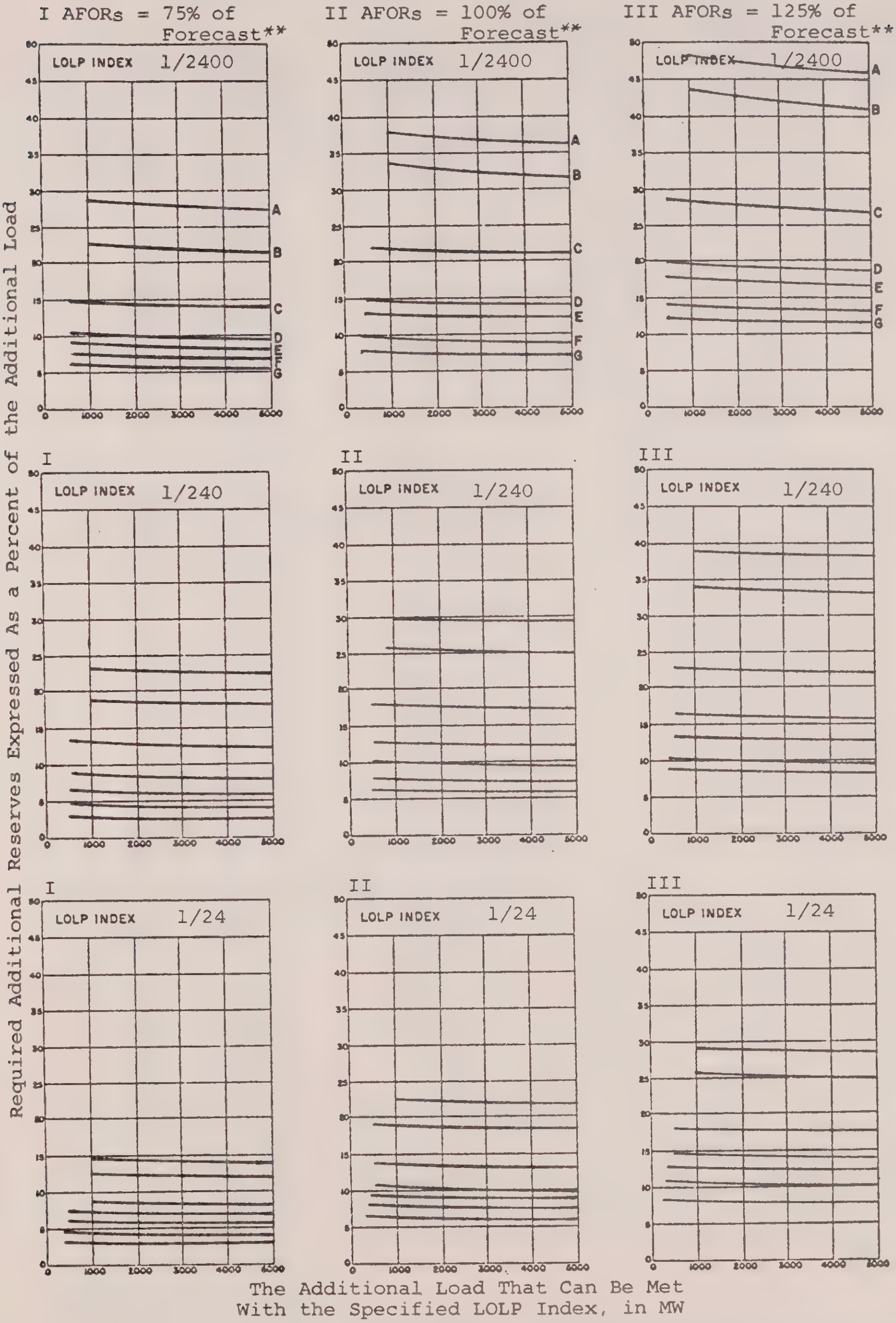
Discounted to 1995
(First Unit In-Service: 1995)



LEGEND:
A = 2 x 33 MW Combustion Turbines
B = 4 x 200 MW Fossil (US Coal)
C = 4 x 500 MW Fossil (US Coal)
D = 4 x 750 MW Fossil (US Coal)
E = 4 x 300 MW CANDU Nuclear
F = 4 x 500 MW CANDU Nuclear
G = 4 x 850 MW CANDU Nuclear
H = 4 x 1250 MW CANDU Nuclear

FIGURE 11 - 13

The Required Additional Generating Reserves,
Expressed As a % of the Additional Load That Can Be Supplied
With a Specified Target Reliability, for the
Addition* of a Series of Identical Generating Units



Unit Additions

	Size in MW	Type	Forecast** AFOR %
A	1250	N	12
	1200	F	12
B	1000	F	12
C	850	N	10
	750	F	10
D	600	N	9
	500	N	9
E	500	F	8
F	300	N	8
G	200	N	8

* Additional units added to Ontario Hydro's existing and committed system as of January 1976, plus Bruce B GS and Darlington GS.

** 1975 forecast of mature AFORs.

FIGURE 11 - 13

FIGURE 11 - 14

Estimates of the Required Percent Reserve Capacity
Associated With a Major Series of Additions of Identical Units*

Type of Units MW	Type of Units Type	Forecast** AFOR, %	Required Reserve As % of Load: AFORs 75% of Forecast	Required Reserve As % of Load: AFORs 100% of Forecast	Required Reserve As % of Load: AFORs 125% of Forecast
I Loss of Load Probability 1/2400					
A. 1250	Nuclear	12)	23	32	42
1200	Fossil	12)			
B. 1000	Fossil	12	20	27	36
C. 850	Nuclear	10)	14	19	25
750	Fossil	10)			
D. 600	Nuclear	9)	10	14	19
500	Nuclear	9)			
E. 500	Fossil	8	8	12	16
F. 300	Nuclear	8	6	10	13
G. 200	Nuclear	8	5	7	10
II Loss of Load Probability 1/240					
A. 1250	Nuclear	12)	19	26	34
1200	Fossil	12)			
B. 1000	Fossil	12	16	23	30
C. 850	Nuclear	10)	11	16	21
750	Fossil	10)			
D. 600	Nuclear	9)	8	12	16
500	Nuclear	9)			
E. 500	Fossil	8	7	10	14
F. 300	Nuclear	8	5	8	12
G. 200	Nuclear	8	4	7	9
III Loss of Load Probability 1/24					
A. 1250	Nuclear	12)	13	19	25
1000	Fossil	12)			
B. 1000	Fossil	12	12	17	23
C. 850	Nuclear	10)	8	13	17
750	Fossil	10)			
D. 600	Nuclear	9)	6	10	13
500	Nuclear	9)			
E. 500	Fossil	8	5	8	11
F. 300	Nuclear	8	4	7	10
G. 200	Nuclear	8	4	6	8

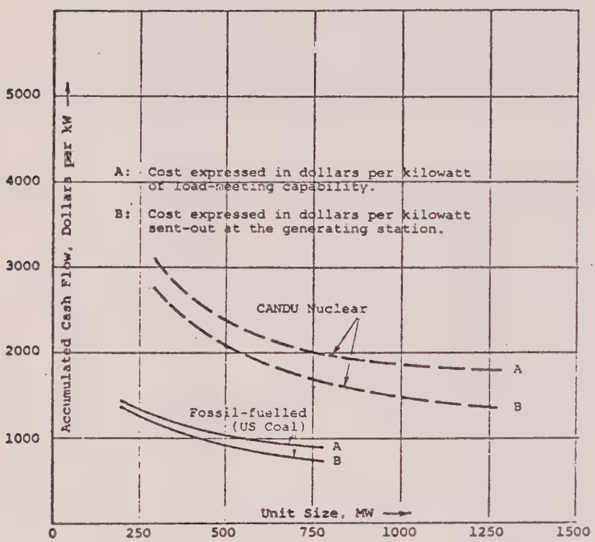
* Additions to Ontario Hydro's existing and committed system as of January 1976, plus Bruce B GS and Darlington GS. The percentages shown correspond to the amounts by which the additions in capacity exceed the additional load that can be supplied with the shown Loss of Load Probability.

** 1975 forecast of mature AFORs.

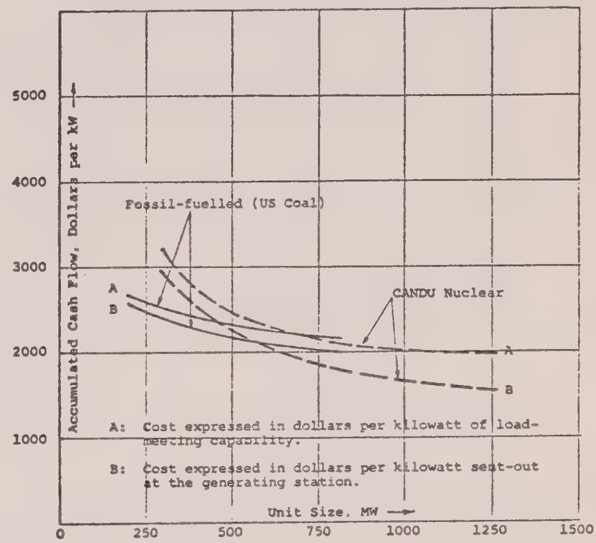
FIGURE 11 - 15

Thermal Generation, Accumulated Cash Outflows at Year 30 For 4-Unit Stations Coming Into Service in 1985, Discounted to 1985

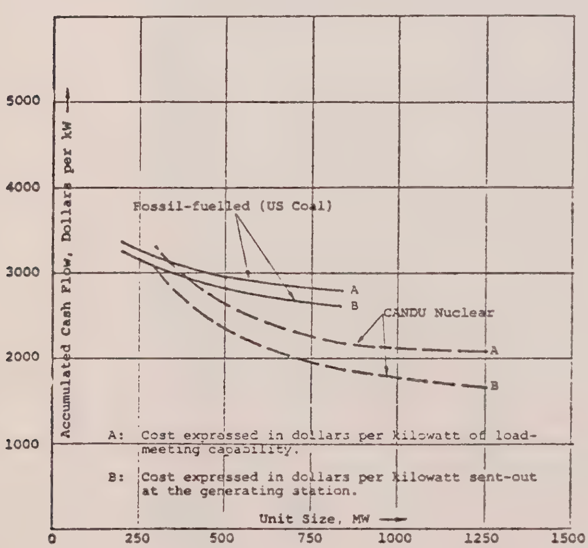
I. Excluding Cost of Fuel



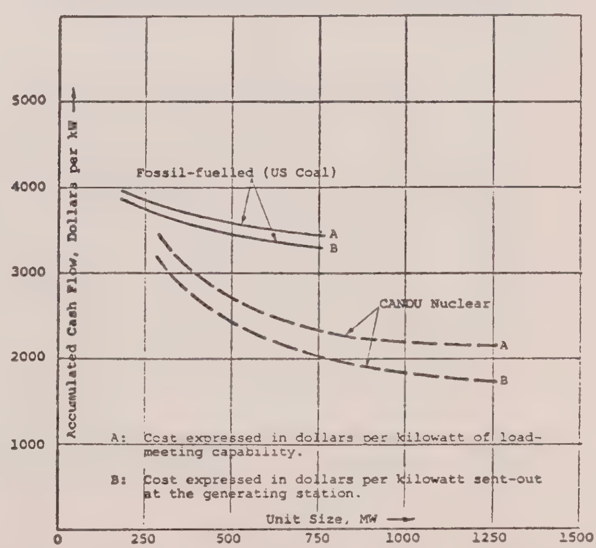
II. Including Cost of Fuel Annual Capacity Factor: 40%



III. Including Cost of Fuel Annual Capacity Factor: 60%



IV. Including Cost of Fuel Annual Capacity Factor: 80%



Notes:
1. Discount factor 10% per annum.
2. LOLP Index 1/2400.
3. AFORs = 100% of Forecast.

FIGURE 11-16

EAST SYSTEM

GENERATION PROGRAM LRF 48

YEAR	ARNPRIOR	HYDRO QUEBEC	NANT	LENNOX	BRUCE	BHWP	STEAM PLANT A	STEAM PLANT B	WES	PICK	BRUCE	DARL	E-15	E-16	E-17	E-18	E-19	E-20	E-21	E-22	E-23	E-24
	HYDRO	PURCH	6-8	1, 3, 4	1-4				1-4	5-8	5-8	1-4	FOS	NUC	NUC	FOS	NUC	NUC	FOS	NUC	FOS	NUC
			3 X 531	3 X 547	4 X 746				4 X 547	4 X 516	4 X 769	4 X 850	4 X 750	4 X 850	4 X 850	4 X 750	4 X 850	4 X 850	4 X 750	4 X 1200	4 X 750	4 X 1200
1976	AUG OCT 39 + 39	NOV -187	DEC	MAR AUG																		
1977		JUNE -1000	APR AUG	FEB	APR NOV		SEP															
1978					AUG		FEB AUG															
1979					AUG	B MAY	FEB															
1980																						
1981						D JUL			DEC	APR												
1982								JUN	JUL	JAN OCT												
1983								APR	FEB AUG	JUL	OCT											
1984								FEB DEC			JUL											
1985											APR	NOV										
1986											JAN	AUG										
1987												MAY	JUL									
1988												FEB	APR	JUL								
1989													JAN OCT	APR	OCT							
1990														JAN OCT	JUL	OCT						
1991															APR	JUL	OCT					
1992															JAN	APR	JUL					
1993																JAN	APR	JAN OCT	JUL			
1994																	JAN	JUL	APR	DEC		
1995																		APR	JAN OCT	DEC	JAN OCT	DEC

FIGURE 11-16

FIGURE 11-17

WEST SYSTEM

GENERATION PROGRAM LRF 48

YEAR	W 1	W 2	W 3	W 4
	FOS	FOS	FOS	NUC
	2 X 155	4 X 200	4 X 200	4 X 200
1976				
1977				
1978				
1979				
1980	OCT			
1981	APR			
1982				
1983		APR OCT		
1984		APR OCT		
1985				
1986				
1987			APR	
1988			APR	
1989				
1990				
1991			APR	
1992			APR	
1993				
1994				APR
1995				APR

FIGURE 11-18

Program LRF 48
Ontario Hydro East System
Peak Load, Capacity and Reserve

December of Year	Generating Capacity MW*	Primary Load MW	Firm Load MW	Reserve Over Firm Load MW	Reserve as % of Firm Load	Firm Load LOLP "x" in 2400	Required Reserves for Shown Generating Capacity MW**	Excess(+) Shortfall(-) in Firm Load-Meeting Capability MW
1976	19464	14760	14343	5121	35.7	0.02	3997	+ 1124
1977	21583	15954	15520	6063	39.1	0.04	5017	+ 1046
1978	22722	17133	16649	6073	36.5	0.09	5273	+ 800
1979	23424	18132	17637	5787	32.8	0.32	5385	+ 402
1980	23428	19268	18746	4682	25.0	6.7	5440	- 758
1981	24577	20392	19870	4707	23.7	8.9	5619	- 912
1982	26293	21640	21118	5175	24.5	6.3	5970	- 795
1983	28634	23168	22646	5988	26.4	2.7	6425	- 437
1984	29601	24800	24278	5323	21.9	14.3	6572	- 1249
1985	31286	26543	26021	5265	20.2	20.6	6747	- 1482
1986	32905	28404	27882	5023	18.0	51.2	7156	- 2133
1987	34505	30392	29870	4635	15.5	127.0	7543	- 2908
1988	37013	32516	31994	5019	15.7	129.0	8146	- 3127
1989	40271	34783	34261	6010	17.5	79.1	8941	- 2931
1990	43571	37205	36683	6888	18.8	53.5	9681	- 2793
1991	46079	39791	39269	6810	17.3	82.2	10110	- 3300
1992	48529	42554	42032	6497	15.5	149.0	10525	- 4028
1993	52637	45504	44982	7655	17.0	90.0	11380	- 3725
1994	56287	48655	48133	8154	16.9	104.0	12254	- 4100
1995	62537	52020	51498	11039	21.4	23.9	13863	- 2824

This table is based on:

- the 1976 load forecast including the effect of the intensified conservation program;
- the 1976 forecast of outage rates; and
- the Bruce Heavy Water Production Plants electric and steam loads being treated as firm loads.

FIGURE 11-19

Program LRF 48
Ontario Hydro West System
Peak Load, Capacity and Reserve

Winter Starting in Year	Generating Capacity MW*	Primary Load MW	Firm Load MW	Reserve Over Firm Load MW	Reserve as % of Firm Load	Firm Load LOLP "x" in 2400	Required Reserves for Shown Generating Capacity MW**	Excess(+) Shortfall(-) in Firm Load-Meeting Capability MW
1976	1013	828	828	185	22.3	0.00	150	+ 35
1977	1153	922	922	231	25.1	0.00	151	+ 80
1978	1153	1010	1010	143	14.2	0.11	152	- 9
1979	1153	1066	1066	87	8.2	18.76	153	- 66
1980	1308	1134	1134	174	15.3	27.92	263	- 89
1981	1463	1195	1195	268	22.4	22.67	322	- 54
1982	1313	1257	1257	56	4.5	521.27	323	- 267
1983	1713	1323	1323	390	29.5	29.48	608	- 218
1984	2113	1391	1391	722	51.9	2.51	769	- 47
1985	2113	1464	1464	649	44.3	4.09	740	- 91
1986	2113	1540	1540	573	37.2	5.73	714	- 141
1987	2313	1620	1620	693	42.8	3.62	768	- 75
1988	2513	1704	1704	809	47.5	1.56	859	- 50
1989	2513	1793	1793	720	40.2	4.38	834	- 114
1990	2513	1886	1886	627	33.2	9.96	810	- 183
1991	2713	1984	1984	729	36.7	6.68	898	- 169
1992	2913	2087	2087	826	39.6	4.31	952	- 126
1993	2913	2196	2196	717	32.7	11.84	938	- 221
1994	3113	2310	2310	803	34.8	7.60	990	- 187
1995	3313	2430	2430	883	36.3	6.24	1058	- 175

* The capacity includes the committed firm purchases from Manitoba Hydro. It also includes the following transfer capability on the East-West interconnection, assuming the load rejection scheme is installed in 1977: 110 MW in 1976-77, 300 MW in 1977-78 and 1978-79, 250 MW in 1979-80 and 1980-81, and 300 MW in 1981-82 and thereafter.

** The required reserve from 1976-77 to 1982-83, inclusive, is assumed to be the largest two units; from 1983-84 onward, it is assumed to be that for a LOLP of 1 in 2400. The regulating margin is included in this column.

This table is based on:

- the 1976 forecast of outage rates; and
- the 1976 load forecast.

FIGURE 11-20

Program LRF48
Ontario Hydro East and West Systems
December Peak Resources

Resource		1976 MW	1976 %	1980 MW	1980 %	1985 MW	1985 %	1990 MW	1990 %	1995 MW	1995 %
Hydraulic	East	5653		5691		5691		5691		5691	
(Dependable)	West	579		579		579		579		579	
	Total	6232	30.6	6270	25.6	6270	18.9	6270	13.7	6270	9.6
Nuclear	East	2284		4984		10489		18908		31008	
	West	0		0		0		0		400	
	Total	2284	11.2	4984	20.4	10489	31.7	18908	41.3	31408	47.9
Coal	East	8000		9502		9502		13252		20002	
	West	97		252		1207		1607		2007	
	Total	8097		9754		10709		14859		22009	
Gas	East	596		596		596		596		596	
	West	0		0		0		0		0	
	Total	596		596		596		596		596	
Oil	East	1485		2188		4376		4376		4376	
	West	0		0		0		0		0	
	Total	1485		2188		4376		4376		4376	
CTU	East	437		456		617		733		849	
	West	29		29		29		29		29	
	Total	466		485		646		762		878	
Total Fossil	East	10518		12742		15091		18957		25823	
	West	126		281		1236		1636		2036	
	Total	10644	52.3	13023	53.2	16327	49.3	20593	45.0	27859	42.5
Firm	East	1009		11		15		15		15	
Purchases	West	200		200		0		0		0	
	Total	1209	5.9	211	0.8	15	0.1	15	0	15	0
Total	East	19464		23428		31286		43571		62537	
	West	905		1060		1815		2215		3015	
	Total	20369	100	24488	100	33101	100	45786	100	65552	100
Primary	East	14760		19268		26543		37205		52020	
Peak (20 min)	West	808		1116		1442		1858		2394	
Load	Total	15568		20384		27985		39063		54414	
Interruptible Load		417		522		522		522		522	

This table is based on:

- The 1976 load forecast, including the effect of the intensified conservation program; and
- The nuclear capacity, assuming the Bruce Heavy Water Production Plants electric and steam loads are treated as firm loads.

Program LRF48

Ontario Hydro East and West Systems

Annual Energy Production

Resource	1980		1985		1990		1995	
	GWh	%	GWh	%	GWh	%	GWh	%
Hydraulic (Median)	34650	28.8	34650	21.4	34650	15.2	34650	11.0
Nuclear	34465	28.7	71596	44.1	124077	54.7	199128	62.9
Coal	41449	34.5	45128	27.8	56447	24.9	71553	22.6
Gas	4598	3.8	4598	2.8	4598	2.0	4598	1.5
Residual Oil	3789	3.2	6237	3.8	7019	3.1	6386	2.0
CTU Oil	6	0	26	0	120	0	122	0
Total Fossil	49842	41.5	55989	34.5	68184	30.0	82659	26.1
Firm Purchases	1226	1.0	0	0	0	0	0	0
Totals	120183	100	162235	100	226911	100	316437	100

Annual Fuel Consumption*

	1980	1985	1990	1995
Uranium	687	1413	2450	3936
Coal - U.S.	11.7	11.1	12.8	15.4
- Western Canadian	3.1	5.1	7.5	10.0
Gas	49	49	49	49
Residual Oil	6.2	9.7	10.8	10.0
CTU Oil	.015	.072	.331	.336

This table is based on:

- The 1976 load forecast, including the effect of the intensified conservation program.
- The 1976 forecast of outage rates.
- The nuclear capacity, assuming the Bruce Heavy Water Production Plants electric and steam loads are treated as firm loads.
- Energy consumed in supplying the BHWP steam load is included in the total annual energy production figures.

*Uranium in 1000's kg, coal in millions of tons of US coal, gas in Bcf, oil in millions of barrels.